Benefit-Cost Analysis for Advanced Metering and Time-Based Pricing

Workshop
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Workshop Objectives

- Present the preliminary results of our analysis of the costs and benefits of AMI and time-based pricing for the five largest utilities
  - These utilities cover about 90% of electricity sales in Vermont
- Obtain feedback regarding assumptions, concerns, etc.
- Discuss next steps

Workshop Agenda

- Project objectives and work plan
- Overview of methodology and analysis approach
- Summary of preliminary statewide analysis
- Summary of individual utility preliminary analysis
- Input assumptions and data documentation
  - Appendix A: Technology Cost Analysis
  - Appendix B: Operational Savings Analysis
  - Appendix C: Demand Response Benefit & Cost Analysis
  - Appendix D: Outage Cost Analysis

Review of Project Objectives and Work Plan

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Project Objectives

- Evaluate the costs and benefits of advanced metering infrastructure (AMI) and increased use of advanced time-based rates as they relate to AMI
- Evaluate the value of potential promulgation of standards and requirements with respect to AMI and time-based rates

Work Tasks

1. Utility-specific and statewide analysis of costs and benefits of AMI
2. Utility-specific and statewide analysis of costs and benefits of time-based rates
3. Analysis of rate design policy enabled by AMI
4. Recommendations regarding implementation mechanisms and timeframes
5. Report summarizing above, experience from elsewhere, barriers to implementation, etc.

Overview of Methodology and Analysis Approach

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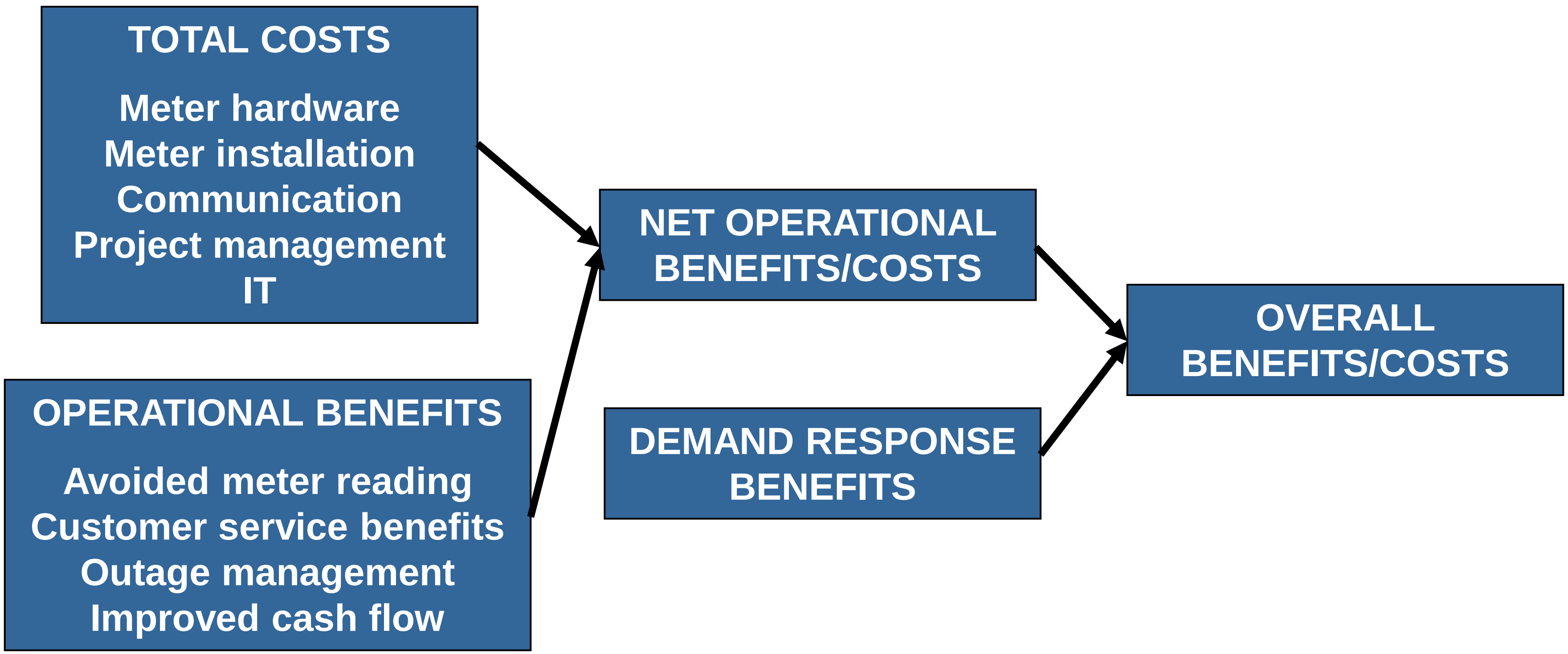
Cost-effectiveness analysis requires examining costs, operational benefits and demand response benefits



Our primary focus is estimating the benefits and costs from a total resource cost (TRC) perspective.

- Costs
  - AMI capital and O&M
  - Customer side costs, such as PCTs, IHDs, etc. (have not been quantified)
- Benefits
  - Operational cost savings
  - Avoided G, T & D capital
  - Avoided energy
  - Environmental benefits (too small to consider for DR options examined)
  - Improvements in reliability (quantified in the “adjusted TRC” calculation)
- Some benefits, such as customer bill savings, theft detection, wholesale market price reductions, etc. are income transfers and typically are not included in the TRC test
  - But they can be important considerations for policy makers and they can be large (e.g., wholesale market price reductions might produce benefits equal to 10 to 20% of the avoided capacity and energy benefits)

Demand response benefits derive from changes in customer behavior in response to price signals, incentives and/or information.

- If prices are higher during peak periods relative to other times, or incentive payments are tied to reductions in energy use during peak periods, consumers will reduce peak period usage through load shifting and/or conservation efforts
- If load reductions during peak times are not fully offset by load increases at other times, energy use overall will be lower
- Studies also show that customers who are provided with more timely and/or more granular (e.g., hourly) information about their energy use will conserve energy
  - We have not quantified this benefit

The financial benefits associated with DR and information strategies are estimated as follows

Δ Peak Period Energy Use on High Demand Days x Market Price of Generation Capacity x Generation Performance Factor = Generation Capacity Benefits

Δ Peak Period Energy Use on High Demand Days x Marginal Cost of T&D Capacity x T&D Performance Factor = T&D Capacity Benefits

Δ Peak Period Energy Use x Wholesale Energy Costs During Peak Period - Δ Off-Peak Energy Use x Wholesale Energy Costs During Off-Peak Period = DR Energy Benefits

The analysis presented today is based on three primary work streams

- AMI technology selection and cost analysis
- Operational benefit analysis
- Demand response analysis

AMI technology cost analysis is difficult because Vermont is different

- Many small utilities, highly rural population, hilly-mountainous terrain and large number of transformers and substations per customer mean
  - Some technologies that might work well and be cost effective in many other areas are non-starters in Vermont
  - Accurate technology cost analysis requires detailed information on meter locations, distances between meters, topographical mapping and other factors that will ultimately affect the technology selection for a specific utility—which is beyond the scope of this study
  - For density sensitive technology options, we have used information on the number of accounts in and outside town centers, account density for each town (accounts/sq. mi.), reasonable assumptions about the required number of concentrators and repeaters and sensitivity analysis

Obtaining precise, publicly-available cost data for component details is also a challenge

- We know a lot more than we can say—"We could tell you but then we'd have to kill you."
- When working for a specific utility, vendor specific cost data can be easily protected, even within the context of a regulatory proceeding
- Further complicating the analysis is that vendors are constantly improving their offerings with lower/higher costs and lesser/greater functionality and higher capacity
- Cost estimates are not final until RFPs have been issued, a vendor selected and final contract negotiations have been completed

We considered the following technology options

- Mesh radio
  - Combination of “terrain following” communication with the ability to have tendrils that can cost effectively reach out to low density sites has potential
- PLC—medium speed
  - This technology requires one concentrator per transformer
  - The # number of one and two meter transformers in VT makes this option prohibitively expensive
- PLC—low speed
  - Requires one concentrator per substation
  - Low speed still allows you to obtain interval data daily
- Star radio—long range
  - The high cost of the concentrator combined with low customer density and the impact of hilly-mountainous terrain on coverage make this option a non-starter
- Star radio—short range
  - So far, we have only examined this technology for BED, where it had the highest likelihood of being cost effective

The minimum functionality considered for all systems includes

- Two-way communication
- Interval data daily for all customers
- Meter data management system that supports time-based pricing for a large percent of customers
- MDMS interface with utility CIS system (CSRs can access hourly data on demand, ping meters, etc.)
- We did not include
  - Remote connect/disconnect
  - Interface with in home information displays and/or end-use controls

Deployment Assumptions

- Deployment begins in May 2009
  - 24 month deployment schedule for CVPS and GMP
  - 12 month deployment schedule for all other utilities
- Meter and network installation are outsourced
- Meter Data Management System
  - CVPS and GMP purchase, install and maintain their own system
  - BED, VEC and WEC outsource MDM
  - We haven't identified a cost-effective option for the smaller utilities

Key Operational Savings Categories

- Avoided meter reading costs
  - Labor and overheads for meter readers and supervisors
  - Avoided vehicle and other equipment costs
  - Savings are offset by severance costs (counted on cost side of ledger)
- Field operations
  - Reduced “no light” calls
  - Reduced storm restoration costs
- Call center
  - Fewer bill complaints from estimated bills
- Reduced meter O&M costs during warranty period
  - Normal O&M avoided in all future years and counted as a benefit
  - O&M for new meters is included on cost side of ledger with $0 costs during warranty period

Operational savings we have not quantified

- Reduced energy theft
- Increased meter accuracy

} Income Transfers

- Improved transformer sizing and other distribution planning benefits
- Reduced manual billing and rework (spotty data)
- Remote connect/disconnect costs
  - Requires more detailed analysis beyond the scope of this study if done purely to avoid the cost of connect/disconnect operations
    - It's almost never cost effective to incur incremental costs for all meters so you must examine the turnover rates for targeted customer segments for each utility
  - Some have argued that the reliability option-value associated with this functionality—being able to limit demand for non-essential uses in order to keep electricity on for more essential uses could justify ubiquitous deployment
- There are many other benefit streams that are typically considered as part of a more detailed business case analysis
  - Additional benefits could easily add 10 to 20 percent to the operational benefit stream, or even more

Key Inputs for DR Analysis

- Number of customers by tariff class
- Average annual energy use
- Energy use by rate period
  - Use during peak hours, off-peak hours, etc.
- Growth in energy use by rate period
- Current average prices
- Time-varying prices or peak time rebates
- Price elasticities
- Customer participation rates
- Marginal capacity costs (G, T & D)
- Wholesale energy costs by rate period

AMI will support a wide variety of DR and information strategies

- **Pure Critical Peak Pricing**
  - Time varying prices on high demand days only
- **Pure Peak Time Rebate**
  - Incentives to reduce energy use during peak periods on high demand days
- **CPP/TOU**
  - Time varying prices on both high demand and other weekdays, with the highest prices occurring on high demand days
- **Time of Use**
  - The same time-varying prices on all weekdays—not really a dynamic rate
- **Real Time Pricing**
  - Prices change hourly in response to market conditions

We planned to estimate DR benefits for pricing scenarios

- A voluntary peak-time rebate program with incentives paid to reduce load during peak hours on 12 high-demand days for all utilities
  - Residential awareness rate of 50%, business awareness rate of 25%
  - Peak time rebate equal to 75¢/kWh
  - Marketing costs equal $2/customer per year for first 2 years, $1 thereafter
- A voluntary, opt-in, pure CPP rate (only for CVPS at this point)
  - Residential participation rate of 20%, business rate of 10%
  - Seasonally revenue neutral, peak price adder equal to 65¢/kWh
  - Acquisition costs equal to $50 per participating residential customer, $100 per participating business customer, and 5% churn rate
- A voluntary, out-out, pure CPP rate (only for CVPS at this point)
  - Residential participation rate of 80%, business rate of 70%
  - Marketing costs equal $2/customer per year for first 2 years, $1 thereafter

Price Responsiveness

- California's Statewide Pricing Pilot supported development of electricity demand models that reflect differences in customer characteristics and climate
- We used Vermont values for air conditioning and cooling degree hours by rate period on critical days to estimate price elasticities that are more representative of VT customers
  - A/C saturation data based on BED survey (4% central a/c and 3.2% households with three or more room units)
  - Calculated cooling degree hours from hourly temperature data for 2003 through 2007 obtained from ISO-NE
  - The elasticity of substitution—the % change in the ratio of peak-to-off-peak usage given the % change in the ratio of prices
  - Daily price elasticity-the % change in daily energy use given the % change in daily price

	CA	**VT**
Residential Elasticity of substitution	**-0.086**	**-0.050**
Residential Daily price elasticity	**-0.040**	**-0.035**

Price responsiveness example: Residential CVPS customers

Day Type/ Δ Energy Use	Rate Period	Current Tariff (¢/kWh)	PTR Program (¢/kWh)	CPP Tariff (¢/kWh)
Critical Day	Peak	11.94	86.92	74.34
	Off-Peak	11.94	11.94	9.34
All Other Summer Days	Peak	11.94	11.94	9.34
	Off-Peak	11.94	11.94	9.34
Percentage Δ Energy Use	Peak	n/a	-10.24%	-9.73%

See Appendix C for more information on prices used in the analysis

Aggregate demand response benefits vary with the number of customers & participation rates

Number of Customers By Rate Class/Size			
Utility	Residential	Commercial Rate 1 (Medium customers >10 kW or >20,000 kWh))	Commercial Rate 2 (Other rate targeted at medium or large (<200 kW) customers)
CVPS	131,421	5,039	760
GMP	78.240	3,182	1,614
VEC	36,256	725	152
BED	16,197	0	819
WEC	9,917	0	12
Total	272,031	8,946	3,357

DR benefits also depend on average electricity use during the peak period on peak-demand days

Average Electricity Use During Peak Period On High Demand Days (kWh/hr)			
Utility	Residential	Commercial Rate 1 (Medium customers >10 kW or >20,000 kWh))	Commercial Rate 2 (Other rate targeted at medium or large (<200 kW) customers)
CVPS	0.98	10.95	54.13
GMP	1.04	8.13	30.28
VEC	0.94	14.77	27.96
BED	0.79	n/a	40.13
WEC	0.88	n/a	36.50

These values were estimated using an 8,760 load shape from BED applied to annual usage values for each utility

The contribution to system peak varies significantly by utility and customer segment

Average Peak Demand and Percent of Contribution to Utility Peak By Customer Segment						
Utility	Residential		Commercial Rate 1		Commercial Rate 2	
	Average MW	%	Average MW	%	Average MW	%
CVPS	129	57	55	24	41	18
GMP	81	51	26	17	49	31
VEC	34	69	11	22	4	8
BED	13	28	0	0	33	72
WEC	9	96	0	0	0.4	4

Most of the value from DR arises from five main categories, which can be grouped into capacity impacts and market impacts

Capacity

Generation capacity

Transmission capacity

Distribution capacity

- Value depends on the extent to which the load reduction offsets the need for additional capacity investment
- Is the load reduction coincident with the peak used for planning purposes?

Demand reduction
(during critical periods)

- Load shifting
- Reduced energy use

Market impacts

Energy Supply Costs

Market Clearing Price Impact
(Not Estimated)

- Value depends on the wholesale market prices by rate period
- Who wins? Who losses? And by how much?

The valuation approach for generation capacity is based on New England's Forward Capacity Market

- Capacity markets are designed to:
  - Ensure system reliability, usually by having an installed capacity requirement
  - Pay peaking units so they are available when needed under system critical conditions
- Markets tend toward equilibrium → capacity value
- The FCM is centered around the cost of having a peaking unit available and operational – Cost of New Entry (CONE)
- The value accrued are expected capacity costs that are offset
  - Based on price of capacity at equilibrium
  - Lower demand means a lower installed capacity requirement
  - Line losses are avoided

The inputs into the capacity valuation are widely accepted

- Cost of capacity – based on studies of the costs to have peaking units around and operational
  - ***Value used:*** *FCM transition prices through 2010 and $90 per kW-year thereafter (adjusted for inflation)*
  - ISO-NE: $90 per kW-year
  - Avoided Energy Supply Costs Study: $100 per kW-year

- Installed Capacity Requirement
  - ***Value used:*** ICR in the ISO-NE's 2007 Regional System Plan, kept steady after planning horizon.
  - Currently 14.3%
  - New Regional System Plan proposed increase in the ICR up to 16.6% by 20XX

- Capacity Inflation
  - ***Value used:*** 4.0%
  - NYISO proposed a capacity inflation rate of 7.8% for their ICAP demand curves based on an actual review of peak generator constructions costs
  - AESC did not factor in inflation

- Capacity performance – adjusting for the number and type of hours when the supply is available
  - ***Value used:*** *75.0%*
  - ISO-NE predicts that summer peak load growth will outpace winter peak load growth, which means the capacity value allocation between summer and winter should tilt more so toward the summer

For T&D, relied on capacity value used for valuing energy efficiency and the share of historical and forecast expenditures by each utility devoted to T&D

- VT value of T&D capacity associated with new load growth – $140 per kW-year
- Use ten years of historical T&D expenditures and ten year of forecast expenditures provided to DPS by each provider to determine splits between T & D for each utility
- Used a transmission performance factor of 80%
  - The need for transmission capacity investments tends to be highly coincident with the periods when the DR would be available
- Used a distribution performance factor of 15%
  - The need for distribution capacity is based on local peaks which are less likely to match critical system conditions
- An alternative approach would be to employ a targeted DR valuation approach given the large known transmission investment in the near futures
  - Time value of money X value of the investment X the number of years the project is deferred

The T&D capacity factor varies by provider based on their transmission versus distribution investments

Avoided T&D investment per kW load reduction = T&D capacity value X T&D performance factor

T&D performance factor = % Transmission X 80% + %Distribution X 15%

Provider	T&D Capacity (kW-Year)	Transmission Share	Transmission Performance factor	Distribution Share	Distribution Performance Factor	T&D Performance factor	Avoided T&D per kW of load reduction
BED	140	16.17%	80.00%	83.83%	15.00%	25.51%	$35.71
CVPS	140	14.06%	80.00%	85.94%	15.00%	24.14%	$33.79
GMP	140	20.98%	80.00%	79.02%	15.00%	28.64%	$40.09
VEC	140	4.27%	80.00%	95.73%	15.00%	17.77%	$24.88
WEC	140	14.87%	80.00%	85.13%	15.00%	24.67%	$34.53

One final AMI benefit included in the TRC+ analysis stems from reductions in customer outage costs tied to reductions in outage duration

- Faster outage restoration is widely cited as a benefit of AMI
  - Quicker outage detection
  - Identify outage source location faster, less time testing the lines
  - Ensure all power is restored before the crew leaves
- Outage costs have been extensively studied and quantified
  - They are a function of frequency, outage characteristics (including duration), and customer characteristics
  - A significant share of the outage costs are incurred in the first few minutes of an outage—costs increase at a decreasing rate with duration
  - Typically, over 90% of outage costs are incurred by commercial and industrial customers
  - Commercial value of service is determined via interviews where actual lost production, substituted production, and other factors affecting net outage costs are estimated
  - Residential value of service is determined via choice experiments designed to assess customer's willingness to pay to avoid specific outages

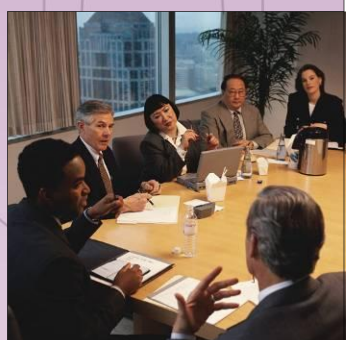
Publicly available data on the impact of AMI on outage duration is limited

- Vendor claims are usually for advanced distribution infrastructure systems (ADI), a complement to AMI
- Claim outage reduction up to 35% - used as an upper bound for AMI without ADI
- Employ a conservative outage reduction (5%) in valuation
- Calculate value of avoided costs under multiple scenarios

Graph Source: GE's Advance Distribution Infrastructure Solutions

Avoided outage costs = costs with current average outage durations – costs with reduced outage durations

- Used residential and commercial customer damage functions found in
  - *A Framework and Review of Customer Outages* (LBNL- 54365)
  - The study pooled ~30 value of service studies from across the U.S. for a comprehensive study of outage costs
  - Regression functions allow users to develop customized outage cost estimates
- Key inputs include:
  - Average outage frequency and duration as indicated by the reliability indices provided in response to the DPS data request.
  - Average annual kWh by customer type
  - Outage onset
  - Average residential household income (from VT Indicators Online)
  - # of employees assumed to be 10 for medium customers and 100 for medium-large customers
- Large (>200kW) Industrial customers were excluded since their outage costs vary widely as a function of detailed inputs that were not readily available (e.g., industry type, backup generation, power conditioning equipment, etc)



Preliminary Statewide Analysis Summary (Top 5 Utilities)

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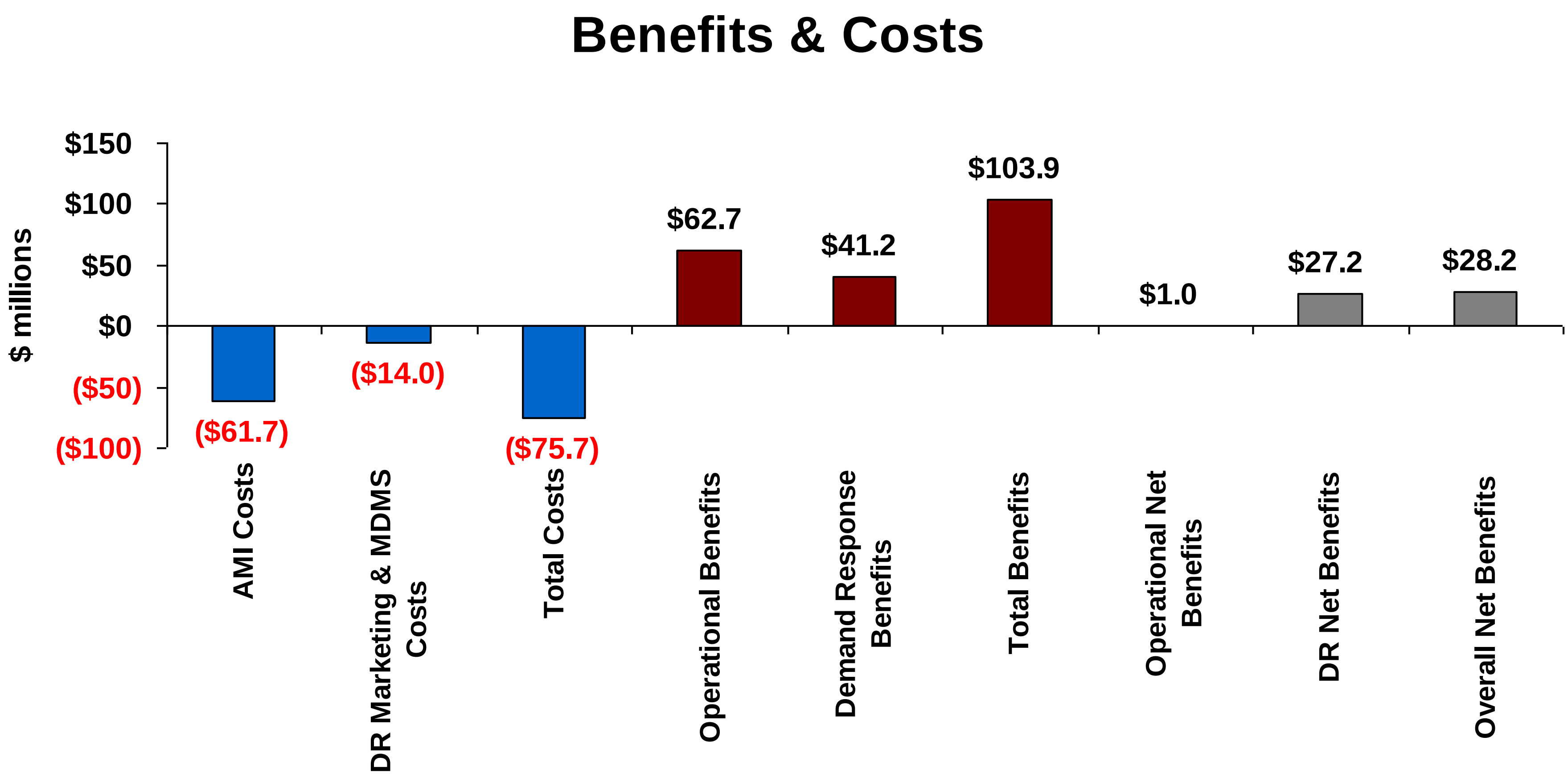
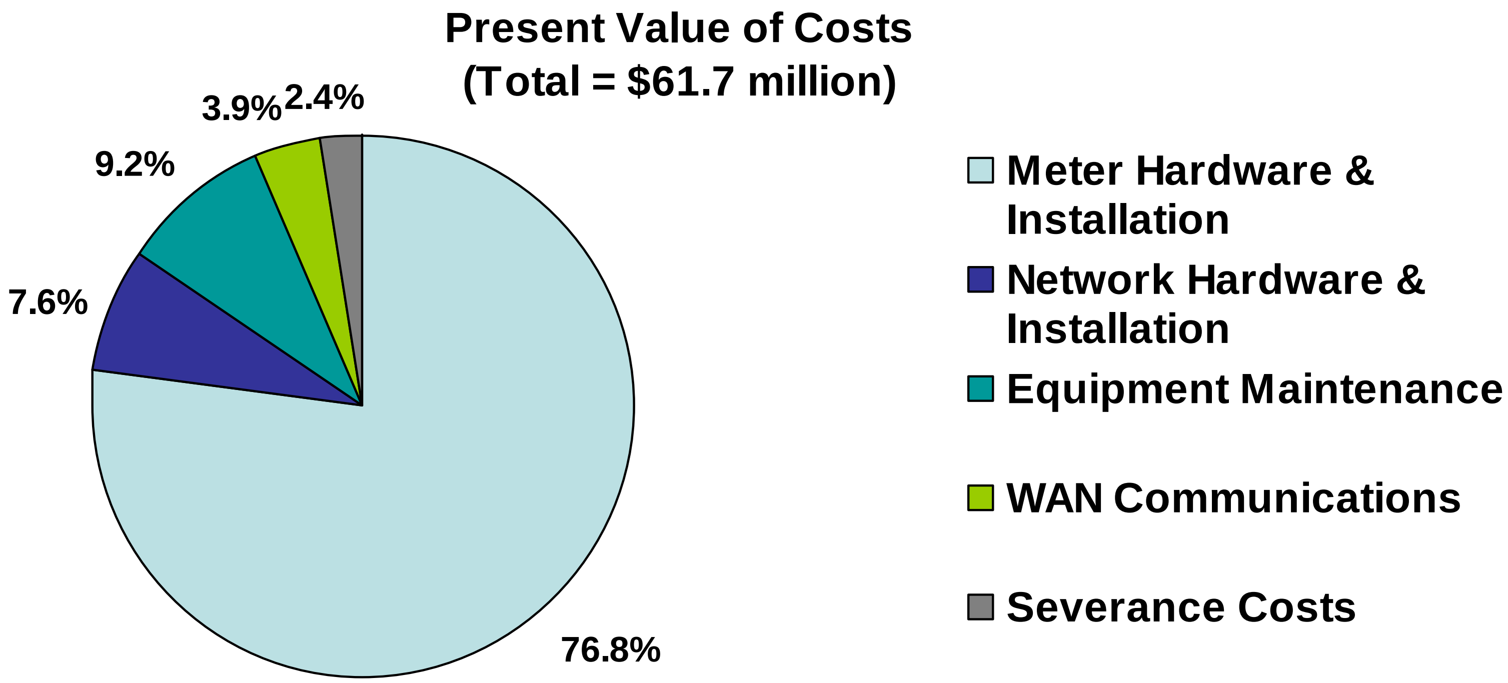
Preliminary results are based on the following

- Power line carrier is the least cost option for CVPS, GMP and WEC
  - PLC and Mesh are very similar for CVPS & GMP, whereas PLC is significantly less costly than Mesh for WEC
  - Mesh had a slight cost advantage over PLC and Star technologies for BED
- We assumed that CVPS and GMP would purchase an MDMS system, whereas VEC, BED and WEC would outsource this functionality
- Base case is a PTR program with a 75 ¢/kWh adder, 50% awareness rate for residential customers and a 25% awareness rate for commercial customers

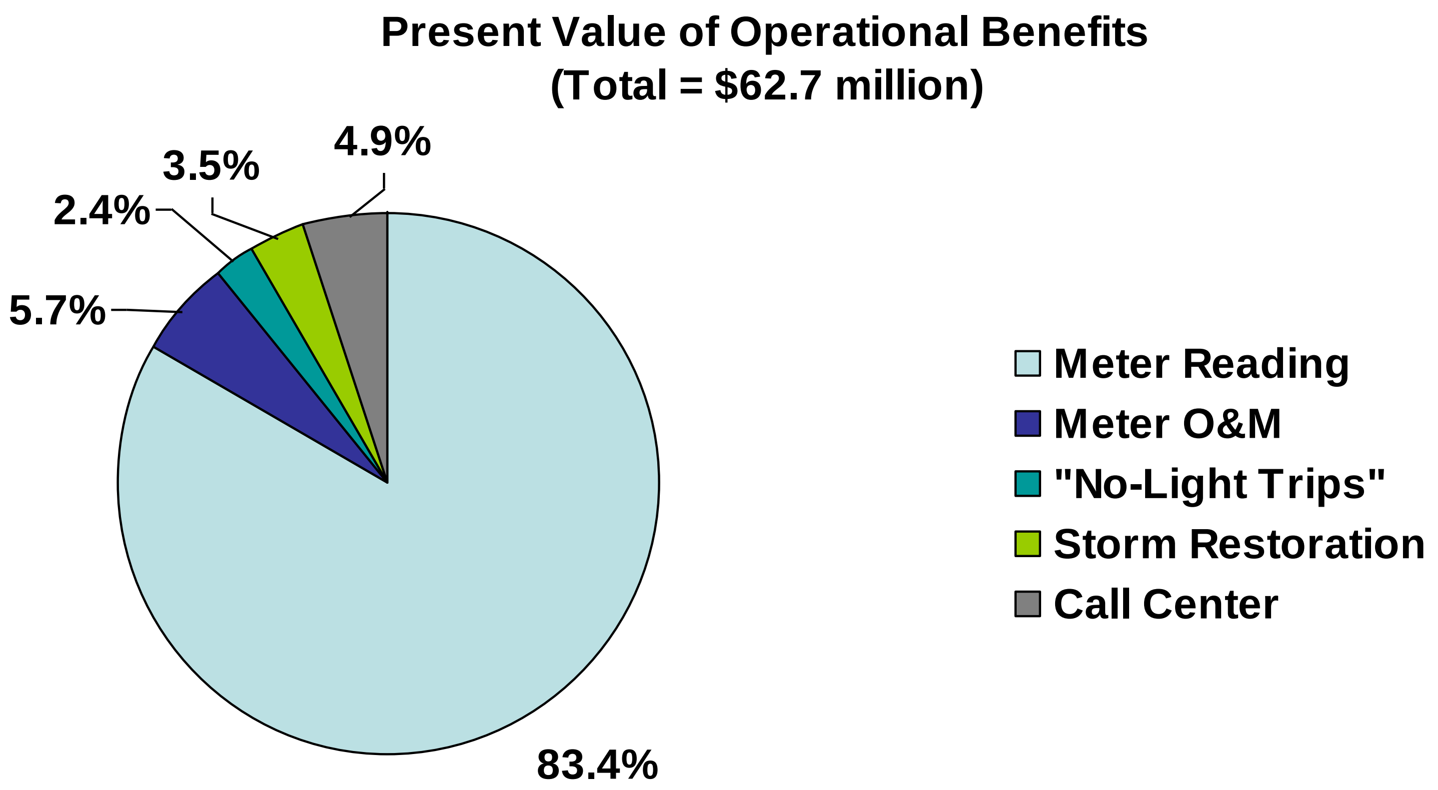
For the "Big 5" utilities combined, AMI is essentially breakeven based on operational benefits but strongly positive when DR benefits are considered



Meter hardware and installation costs account for more than 75% of total costs.

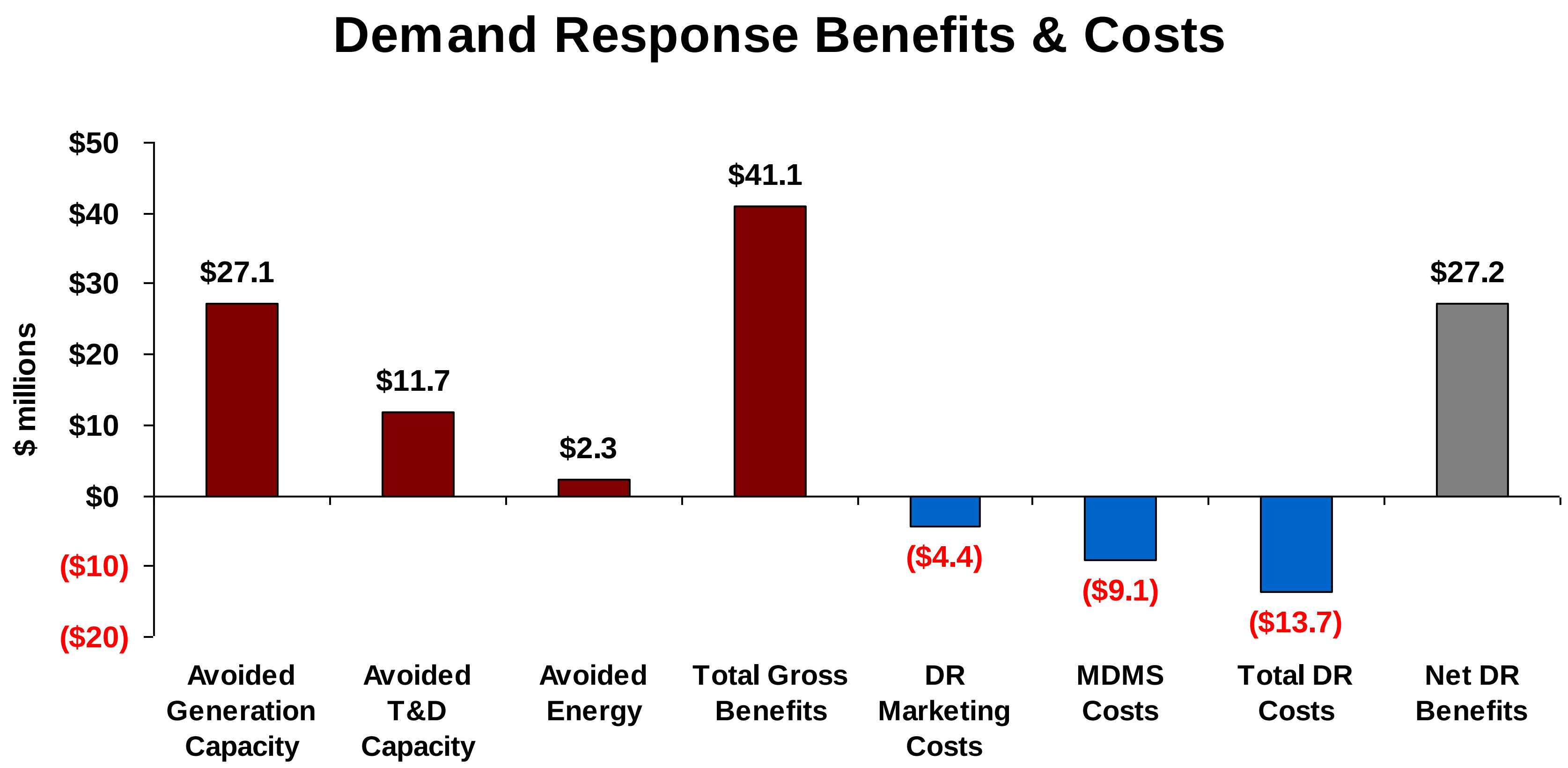


Avoided meter reading costs account for more than 80% of total operational benefits*



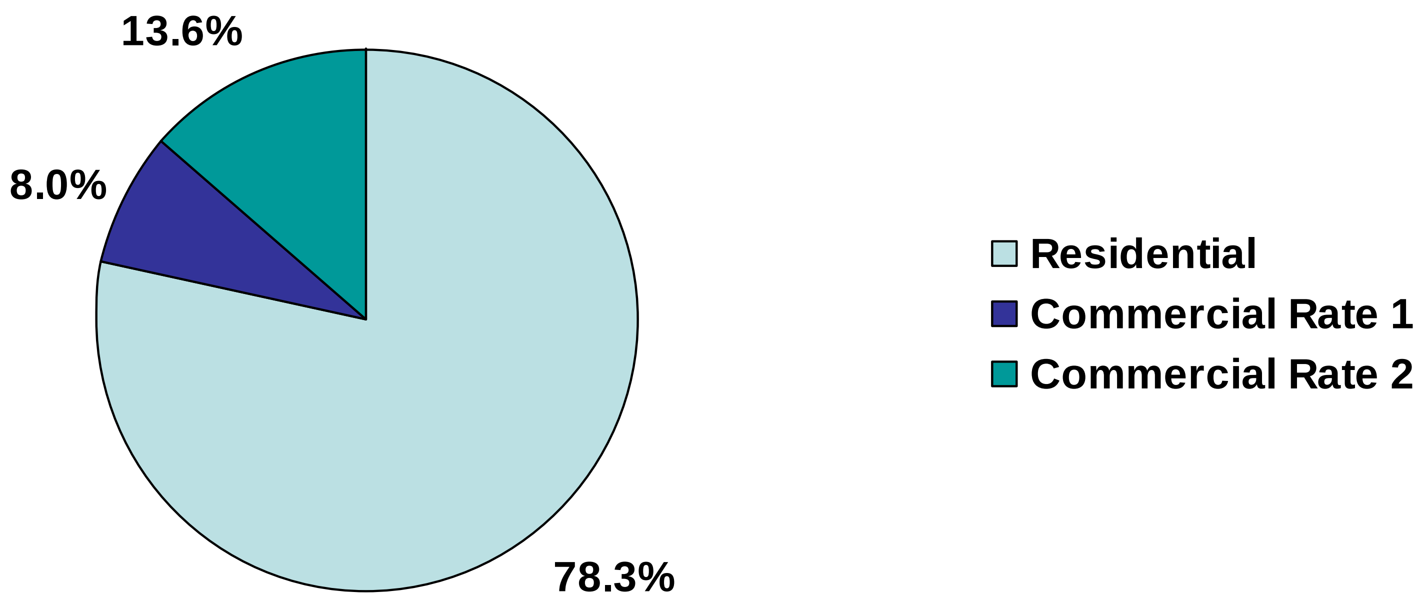
*Additional benefits would likely be identified with more detailed analysis

Demand response generates net benefits equal to $27.2 million, with roughly 66% coming from avoided generation capacity costs

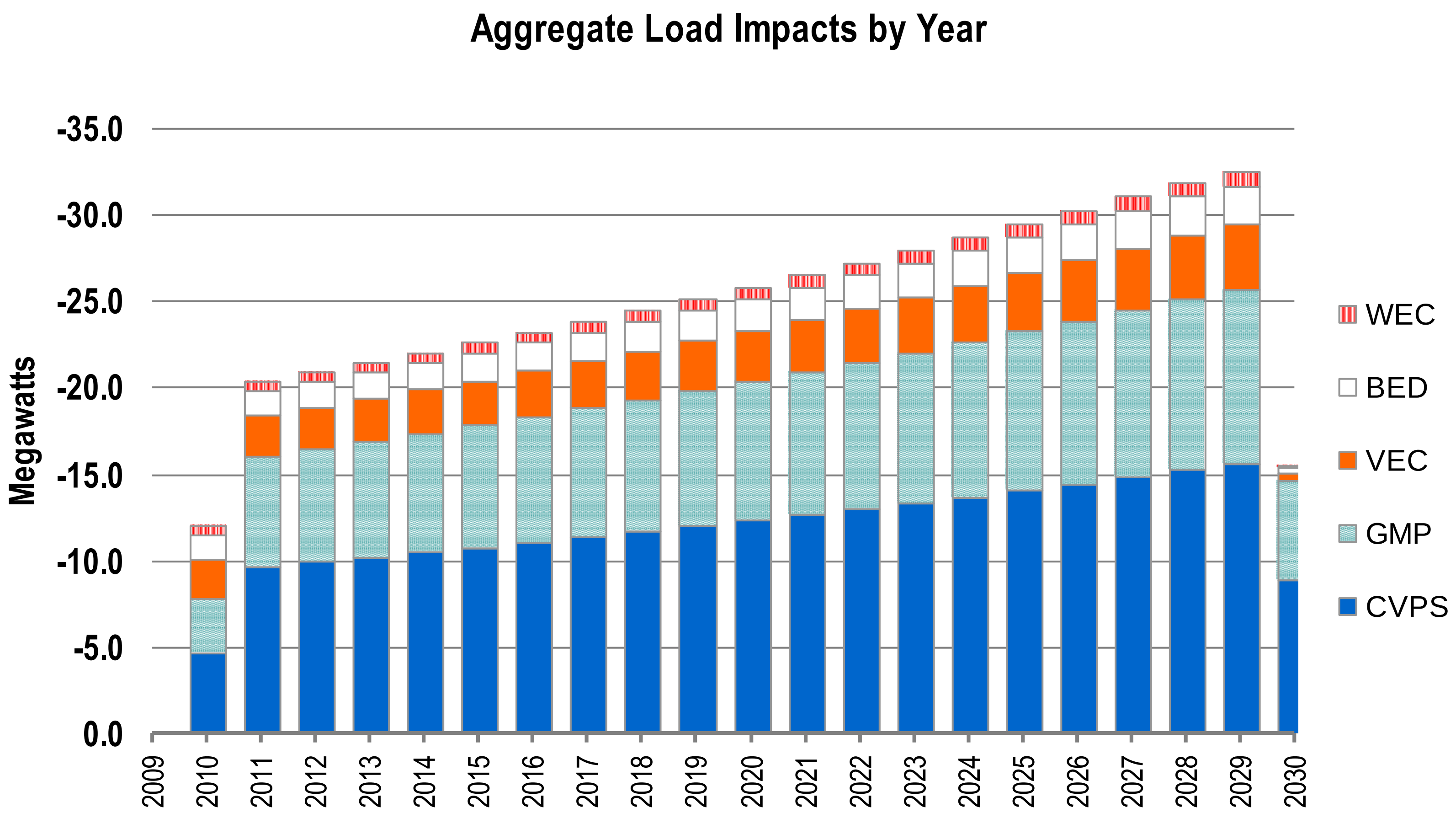


Residential customers account for more than 75% of demand response benefits

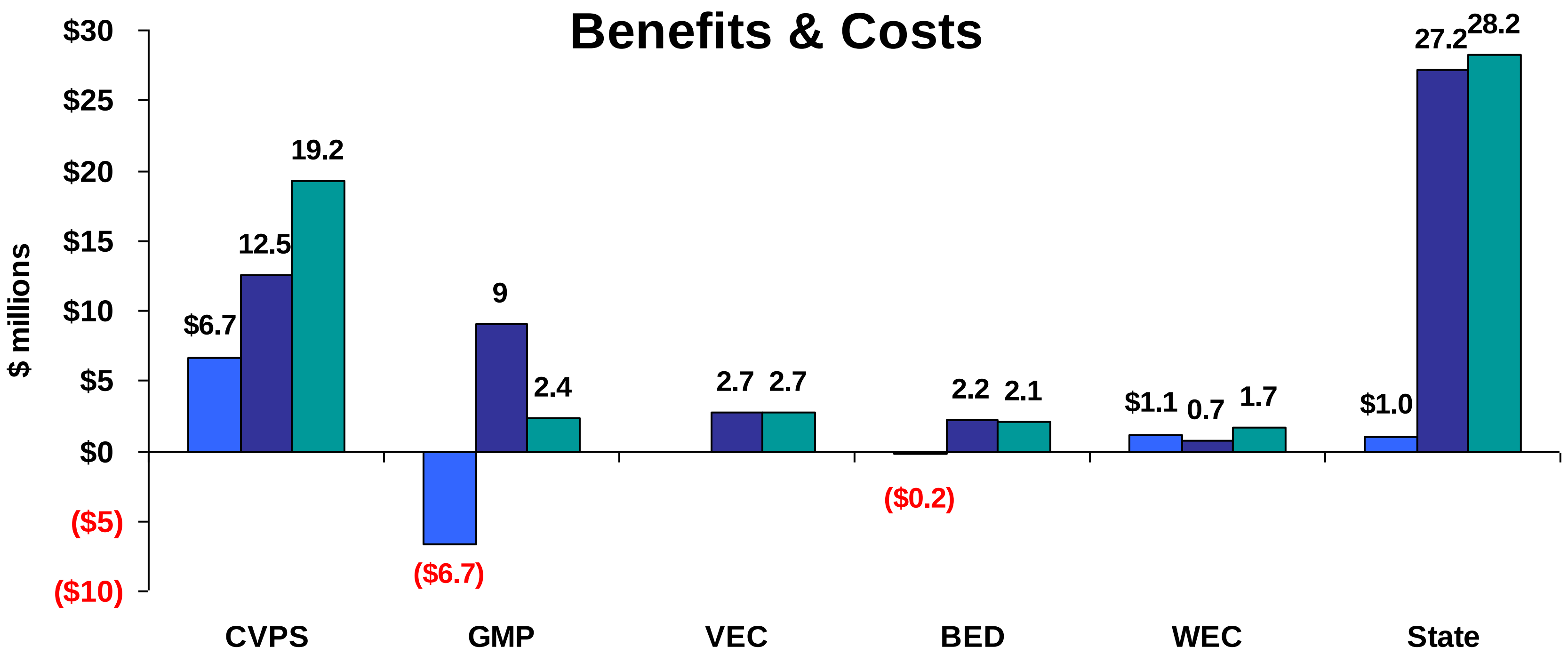
Present Value of Demand Response Benefits (Total = $41.1 million)



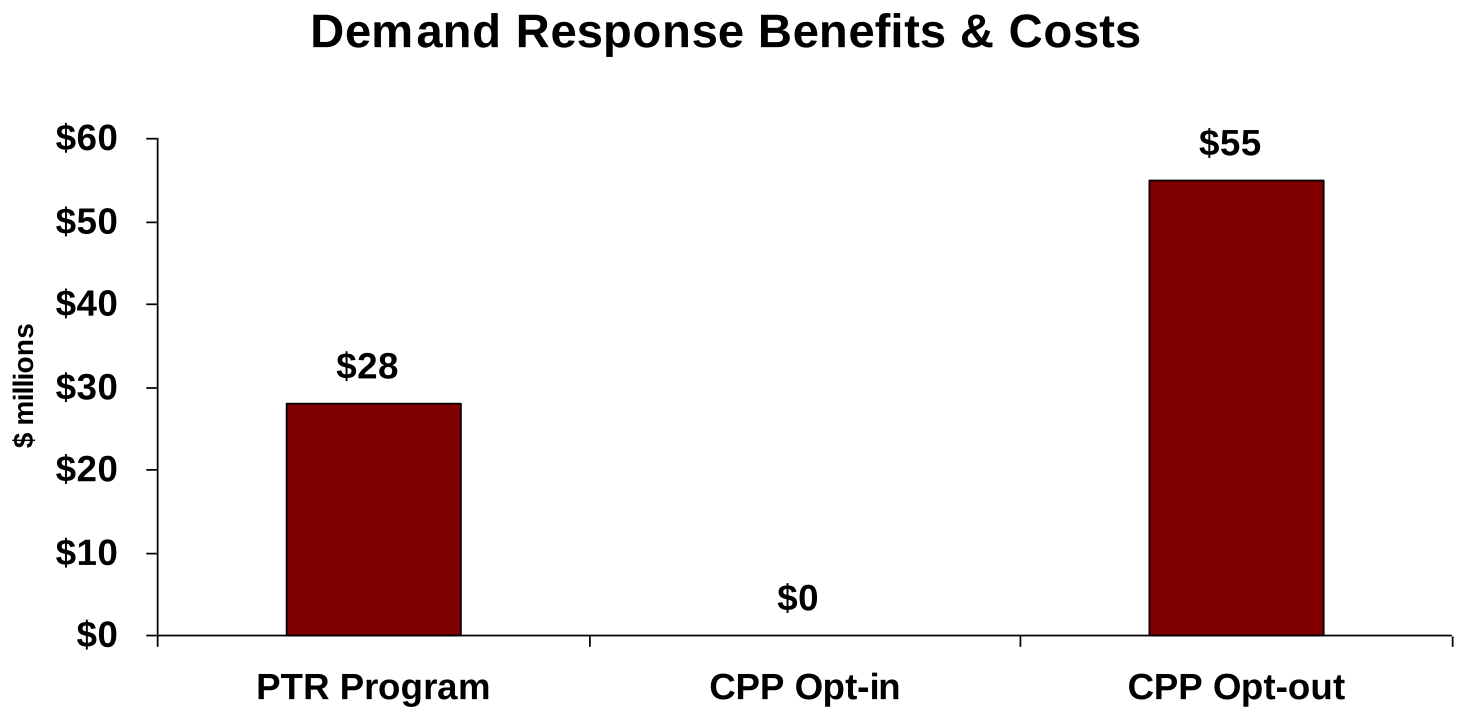
DR can reduce average demand on high demand days by 20 MW starting as early as 2011



As is evident below, "the specifics matter." Costs and benefits vary significantly across companies.

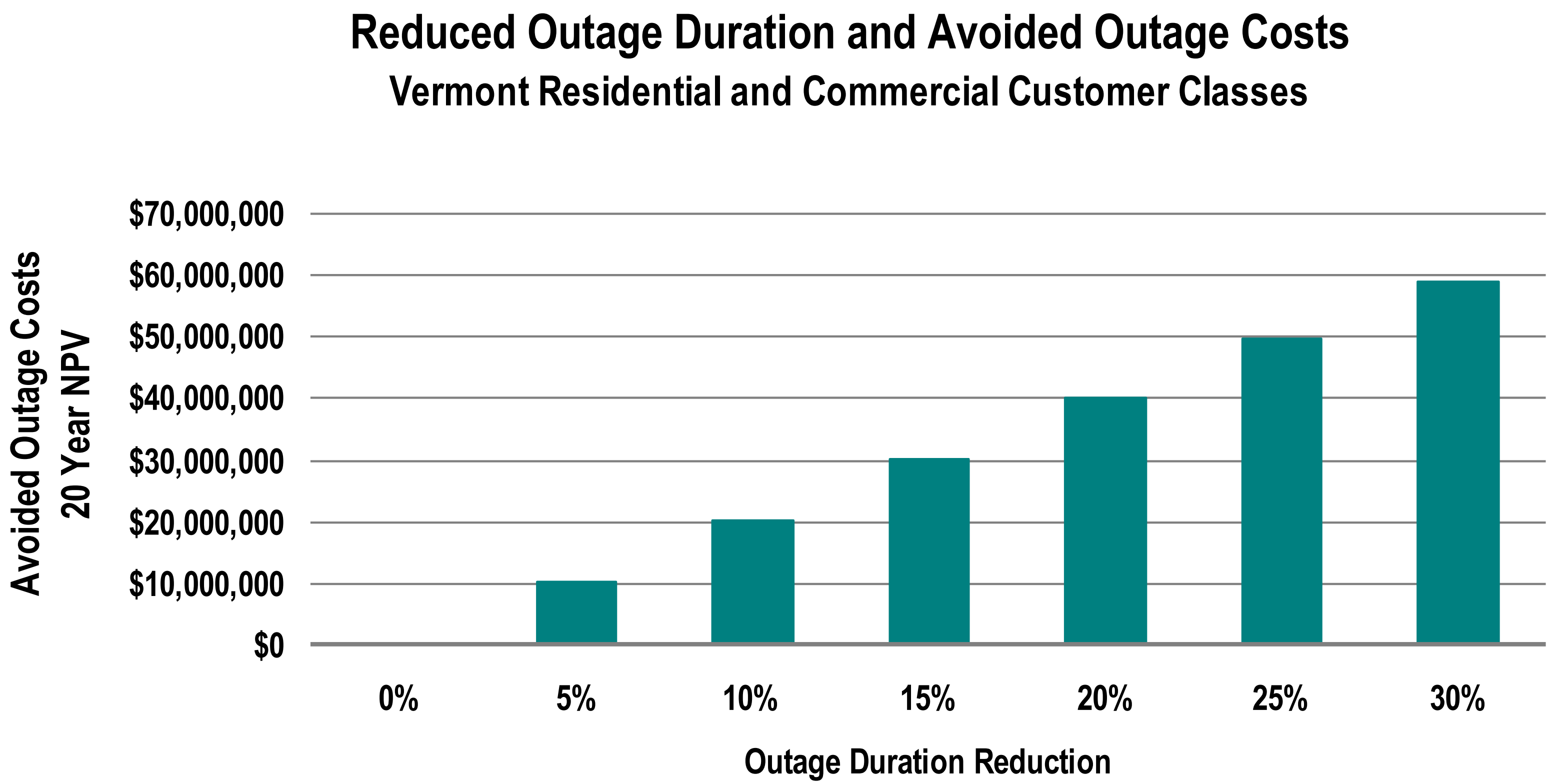


The high customer acquisition costs for an opt-in program combined with low average demand per customer makes it unlikely that an opt-in tariff will be cost effective



Estimates are based on an extrapolation of CVPS analysis. More precise estimates will be presented in the final report

Depending on the impact of AMI on outage duration, the present value of avoided outage costs could range from $10 to $58 million over a 20 year period



Preliminary Analysis Results: Central Vermont Electric System

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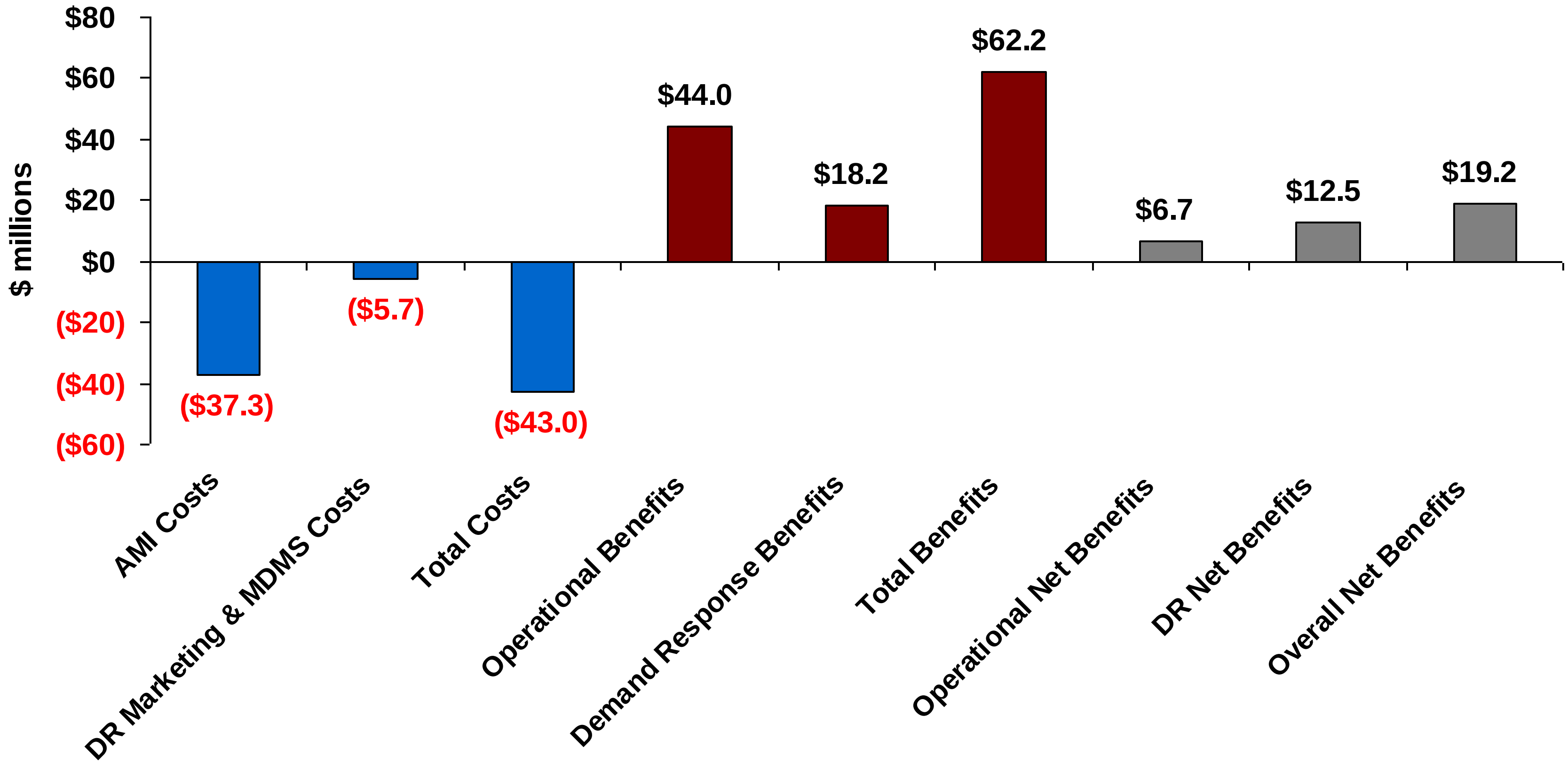
CVPS Characteristics Summary

- Roughly 40% of VT electricity sales and 45% of electricity customers
- Service territory covers 4,700 sq. mi.
- 98 substations
- 70,000 transformers, 20% with only one meter
- Significantly more meters than customers due to separately metered off-peak water heating
- 350,000 calls per year, about 1/3 storm related
- Analysis showed that PLC was the least cost technology option (but mesh was close)

The CVPS business case is strongly positive, with operational net benefits = $6.7 million and overall net benefits = $19.2 million



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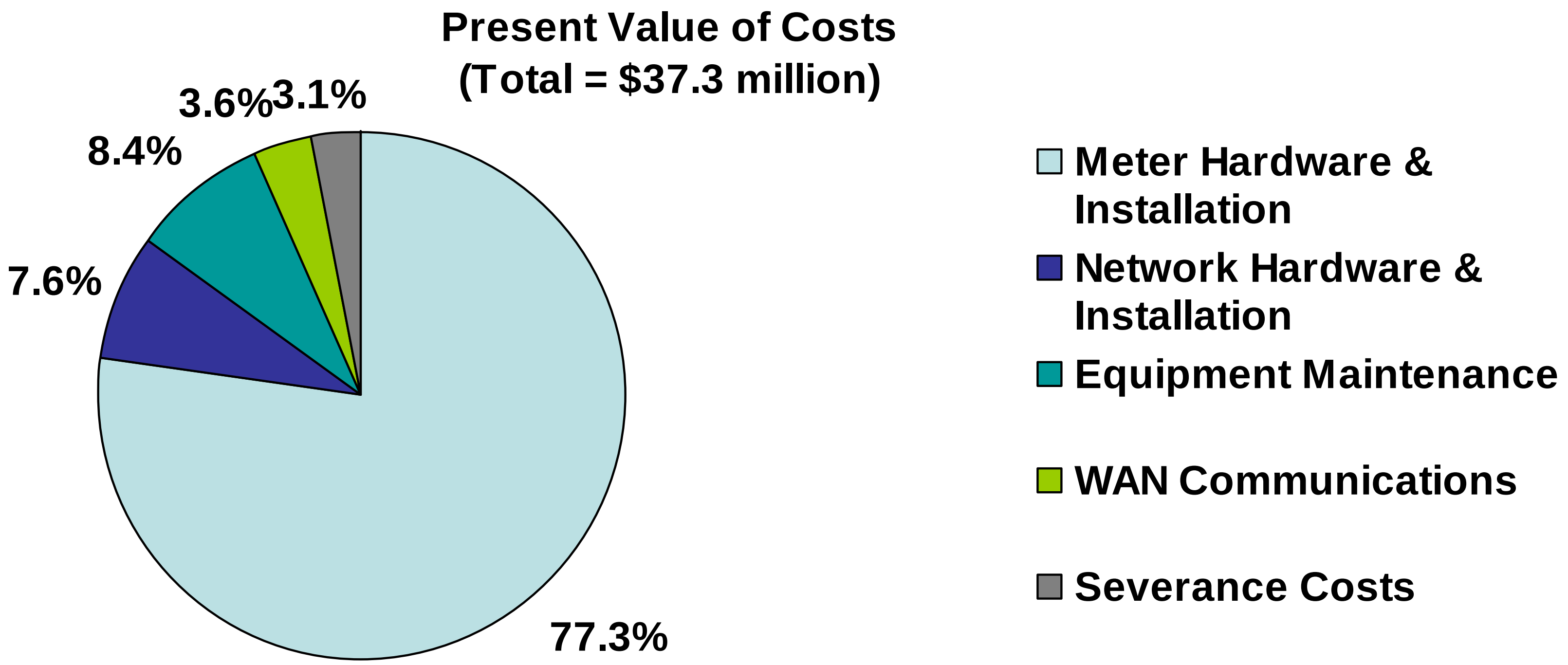
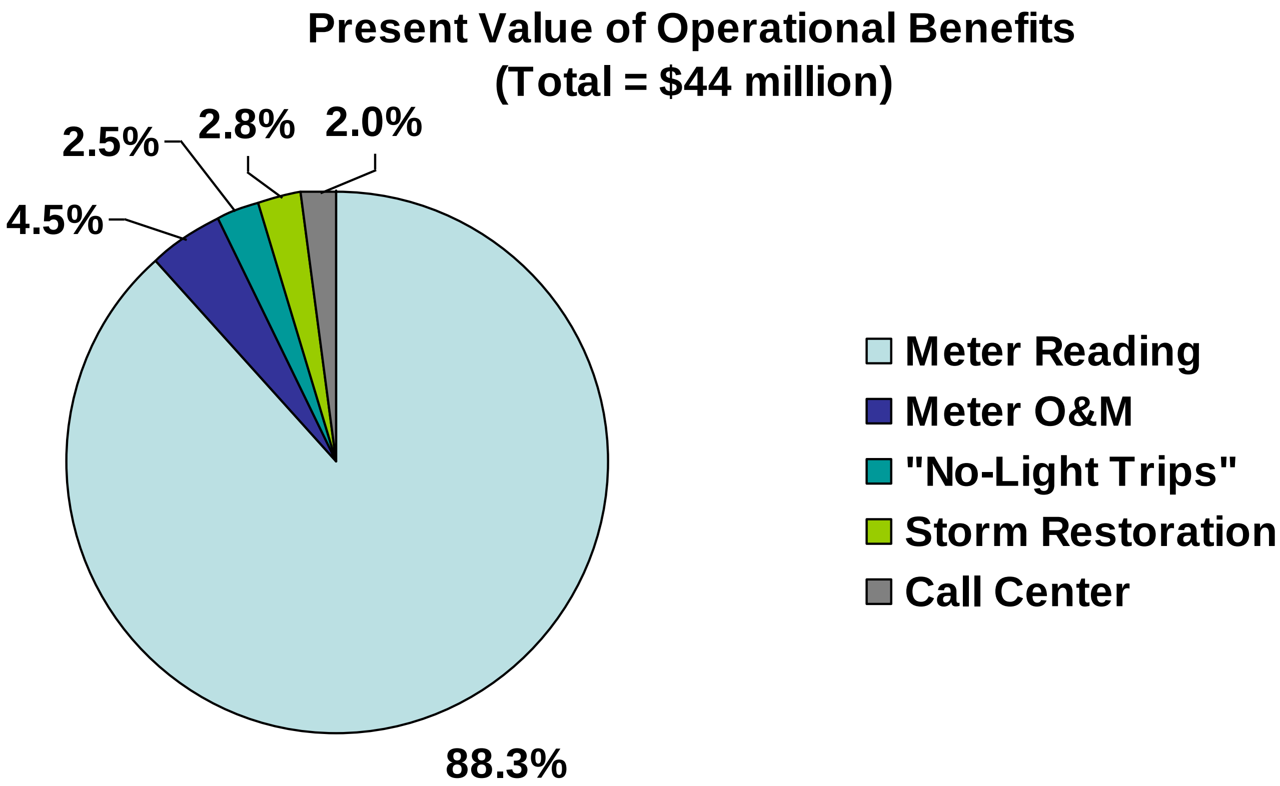
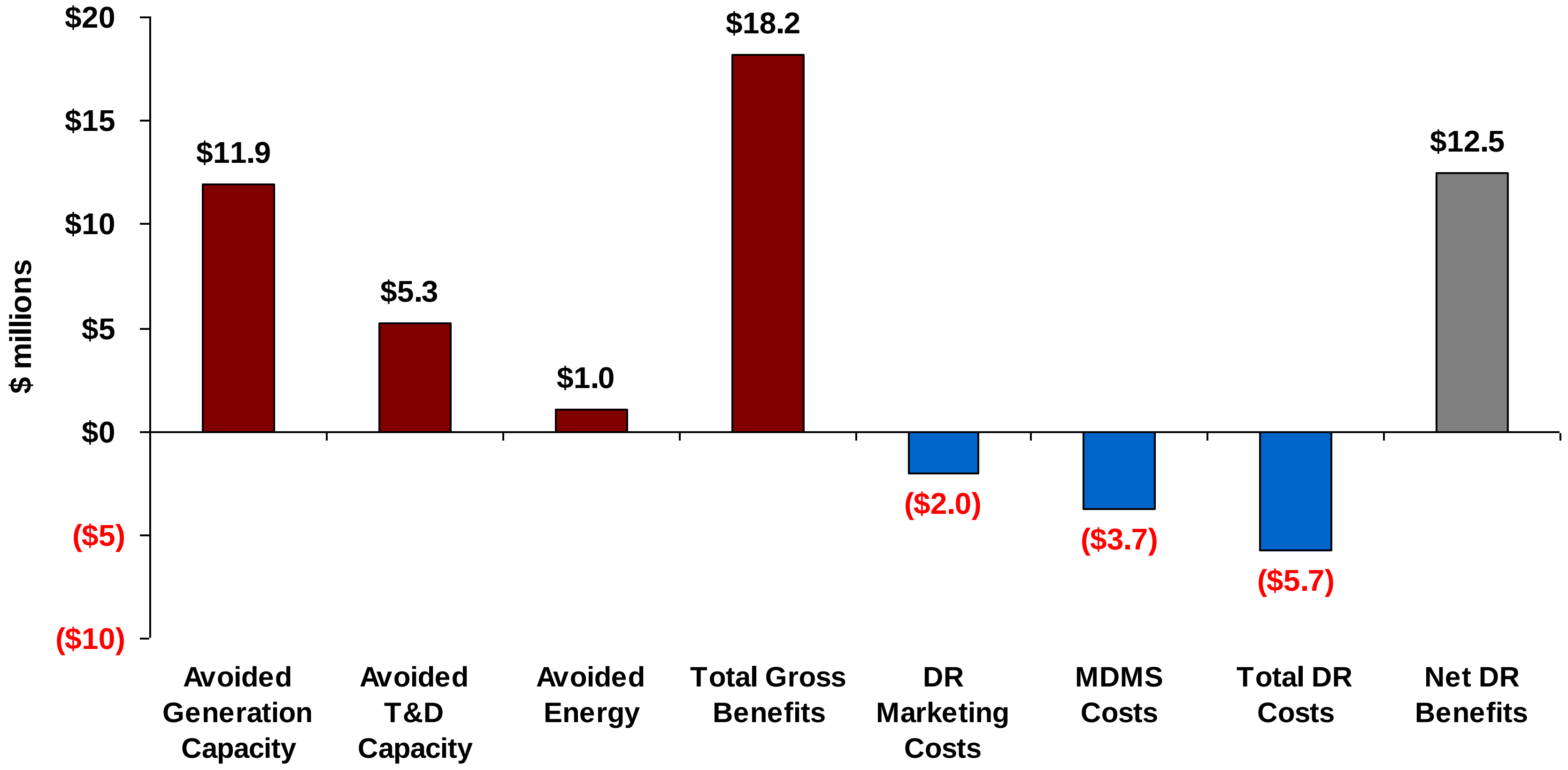


Avoided meter reading costs account for almost 90% of total operational benefits*

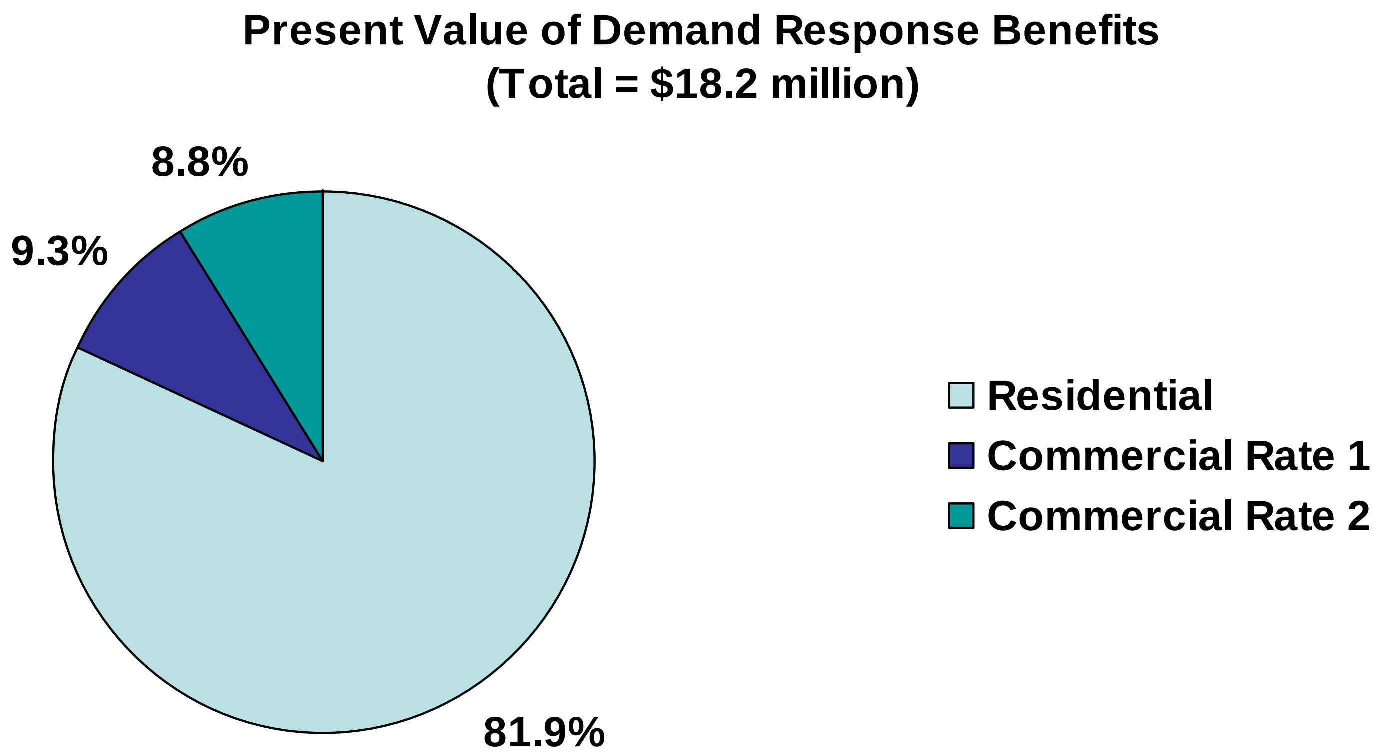


*Additional benefits would likely be identified with more detailed analysis

Demand response generates net benefits equal to $12.5 million



Residential customers account for the vast majority of DR benefits



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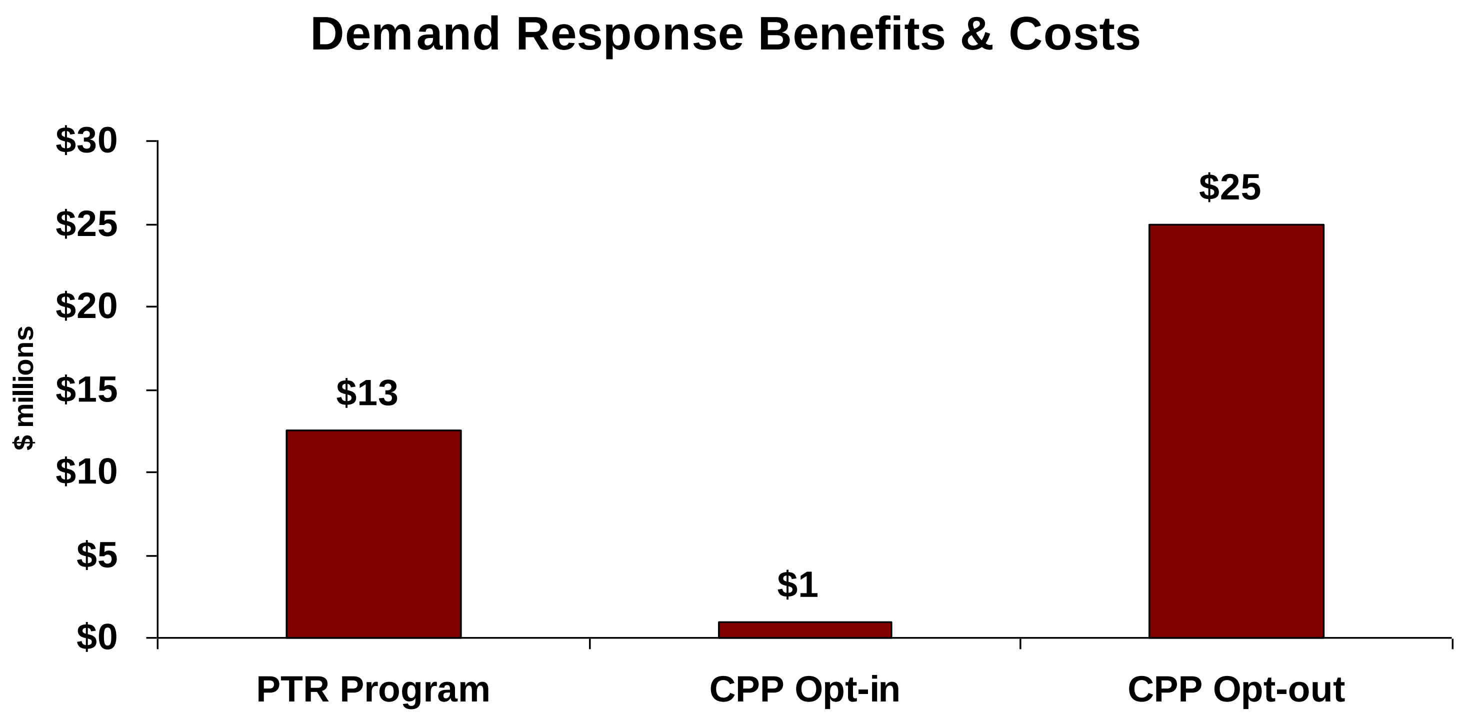
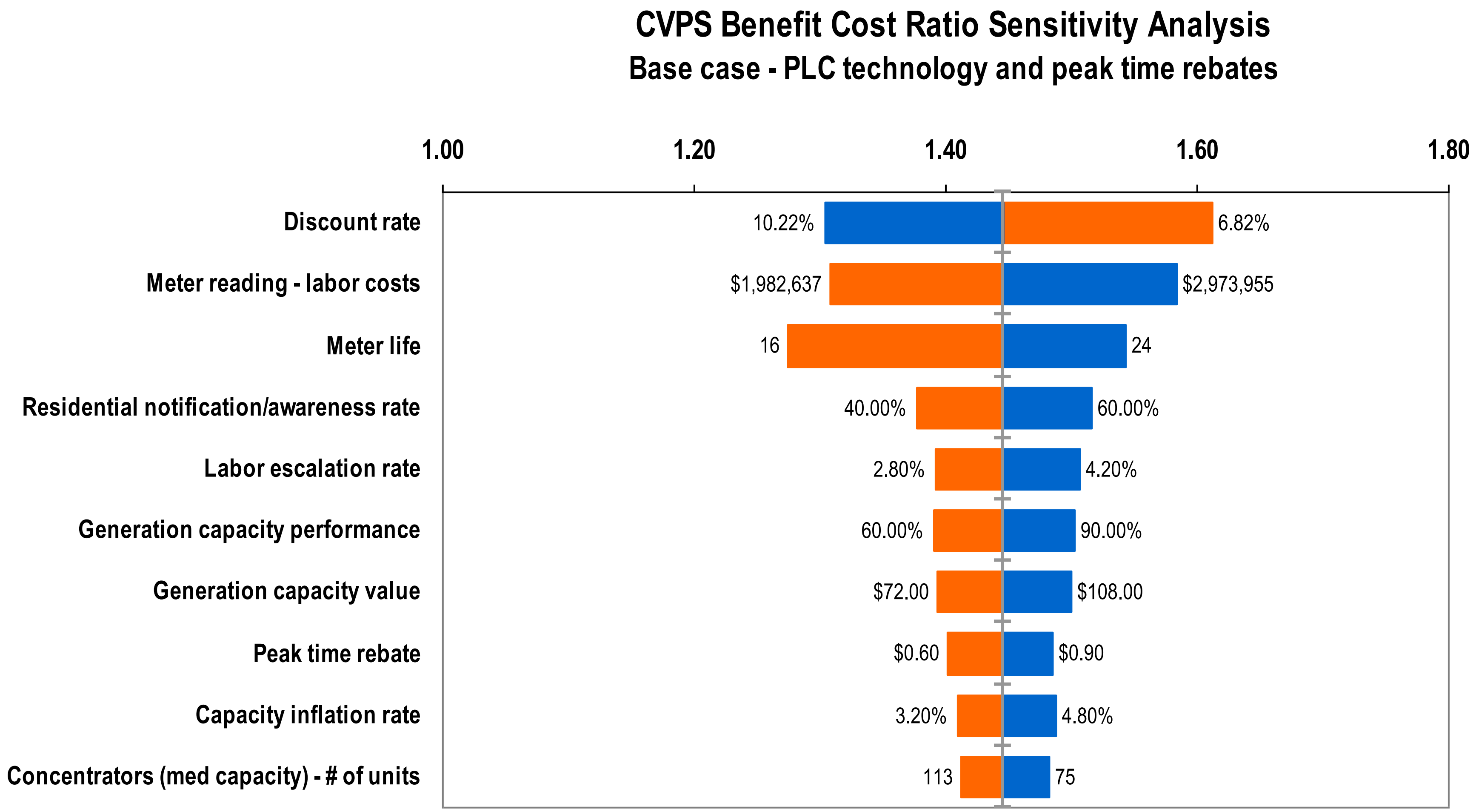
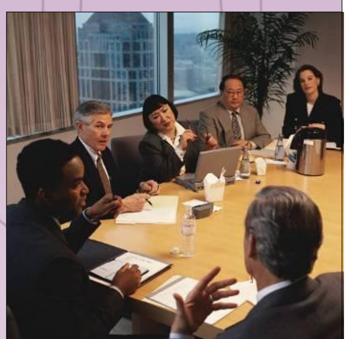


For CVPS, the favorable B/C ratio is quite robust across a wide range of input assumptions





Preliminary Analysis Results: Green Mountain Power

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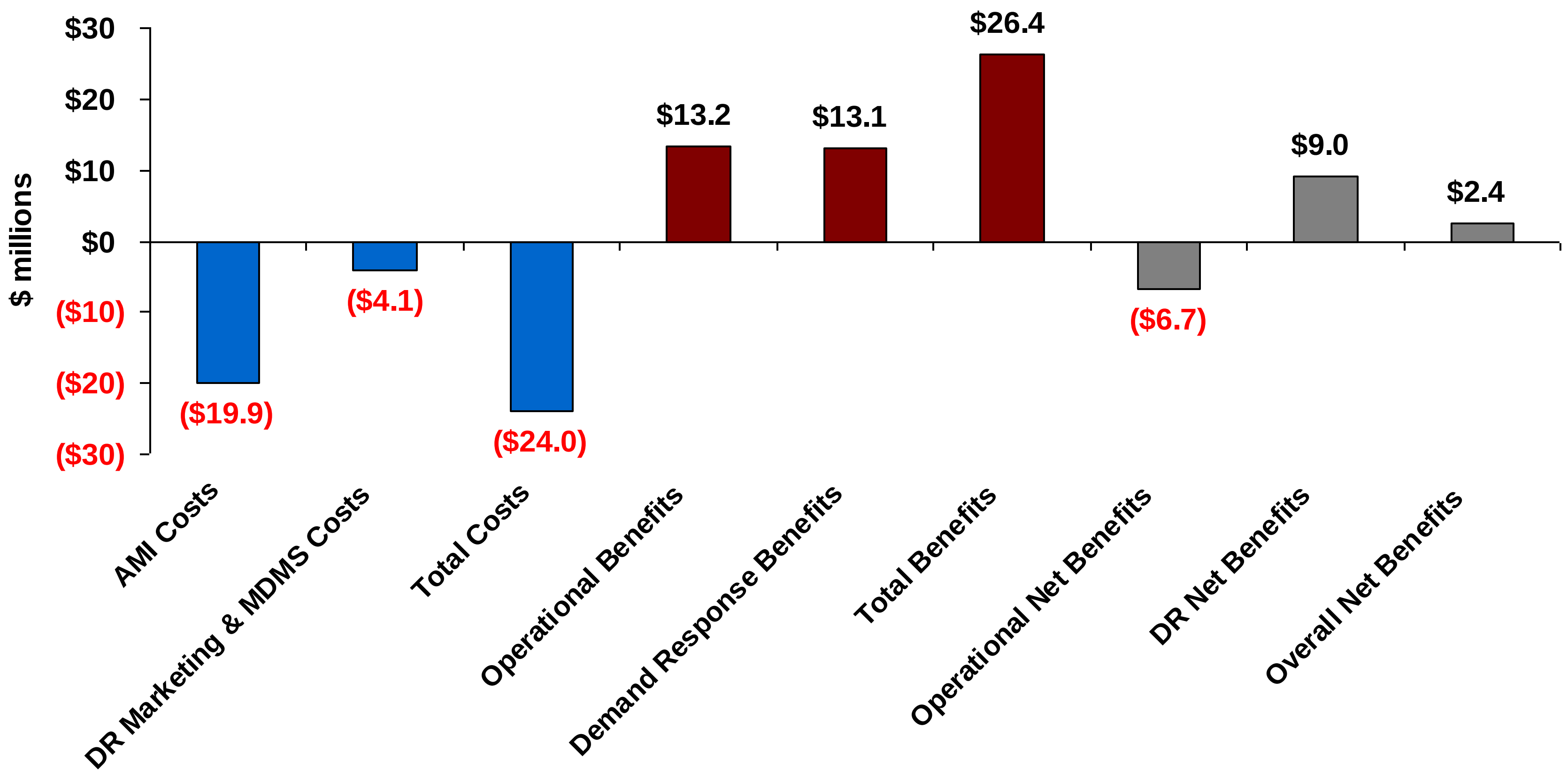
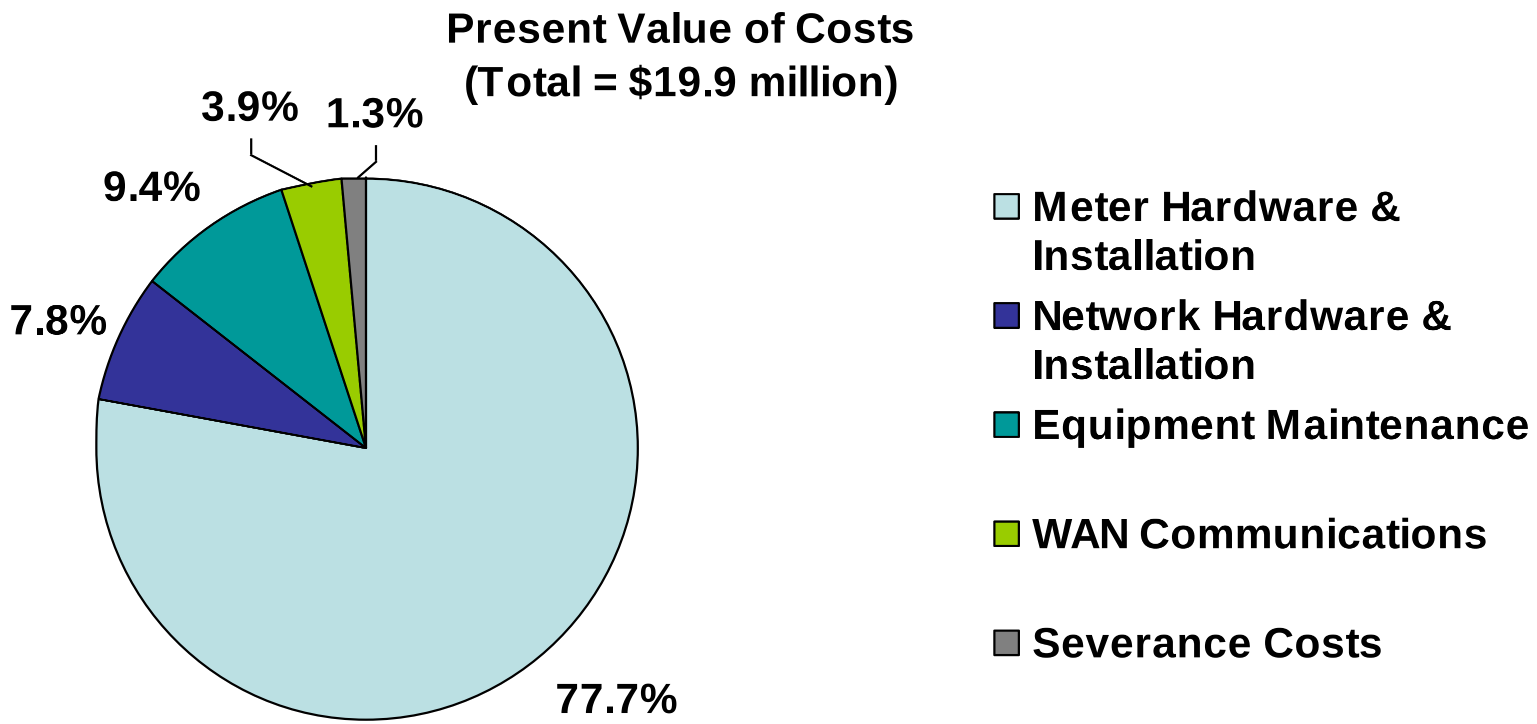
GMP Characteristics Summary

- Accounts for roughly 1/3 of electricity sales and 1/4 of the customers in VT
- 52 substations
- 160,000 calls per year, with more than 75% non-storm related
- Reads meters every other month
- PLC was the least cost technology option

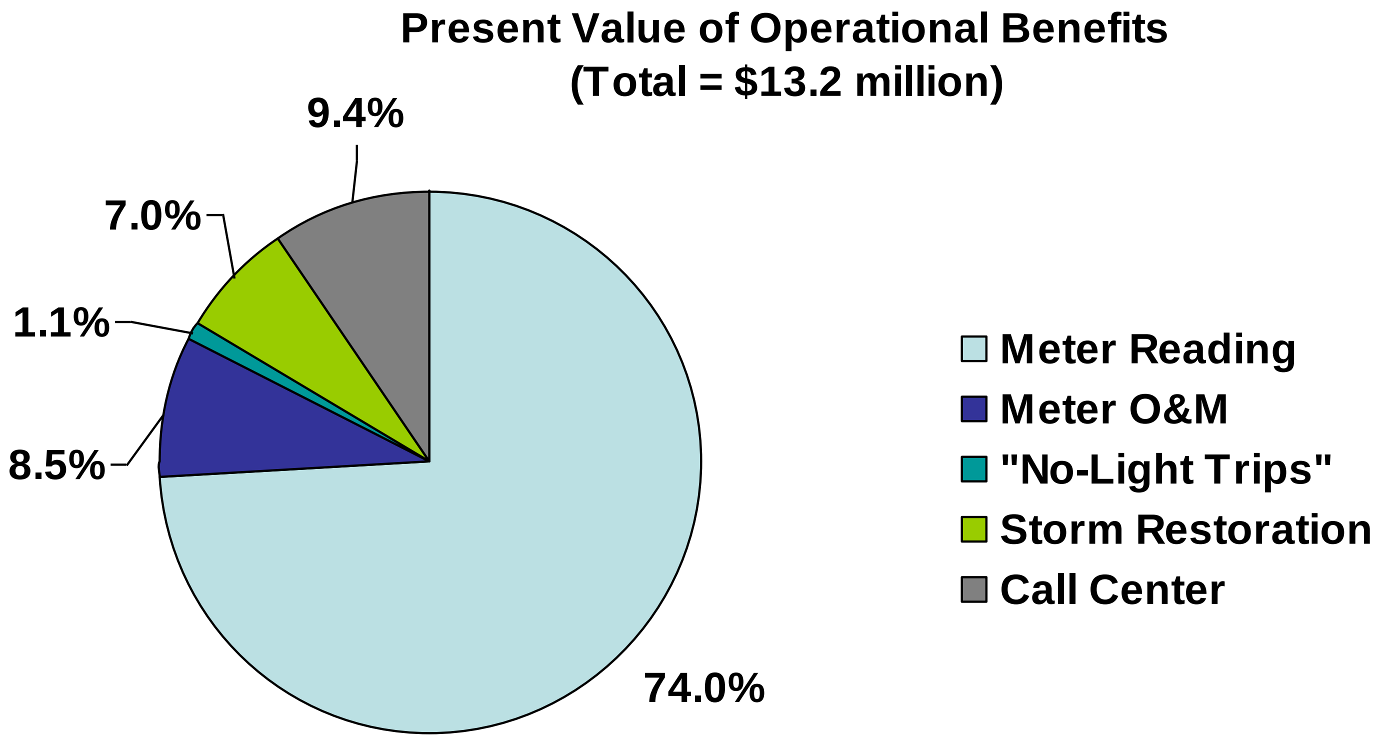
GMP's business case is positive when DR benefits are counted, but negative based on operational benefits. If going to monthly meter reading increased costs by 75%, the case would break even based on operational benefits.



Meter hardware and installation costs account for more than 75% of total costs for GMP

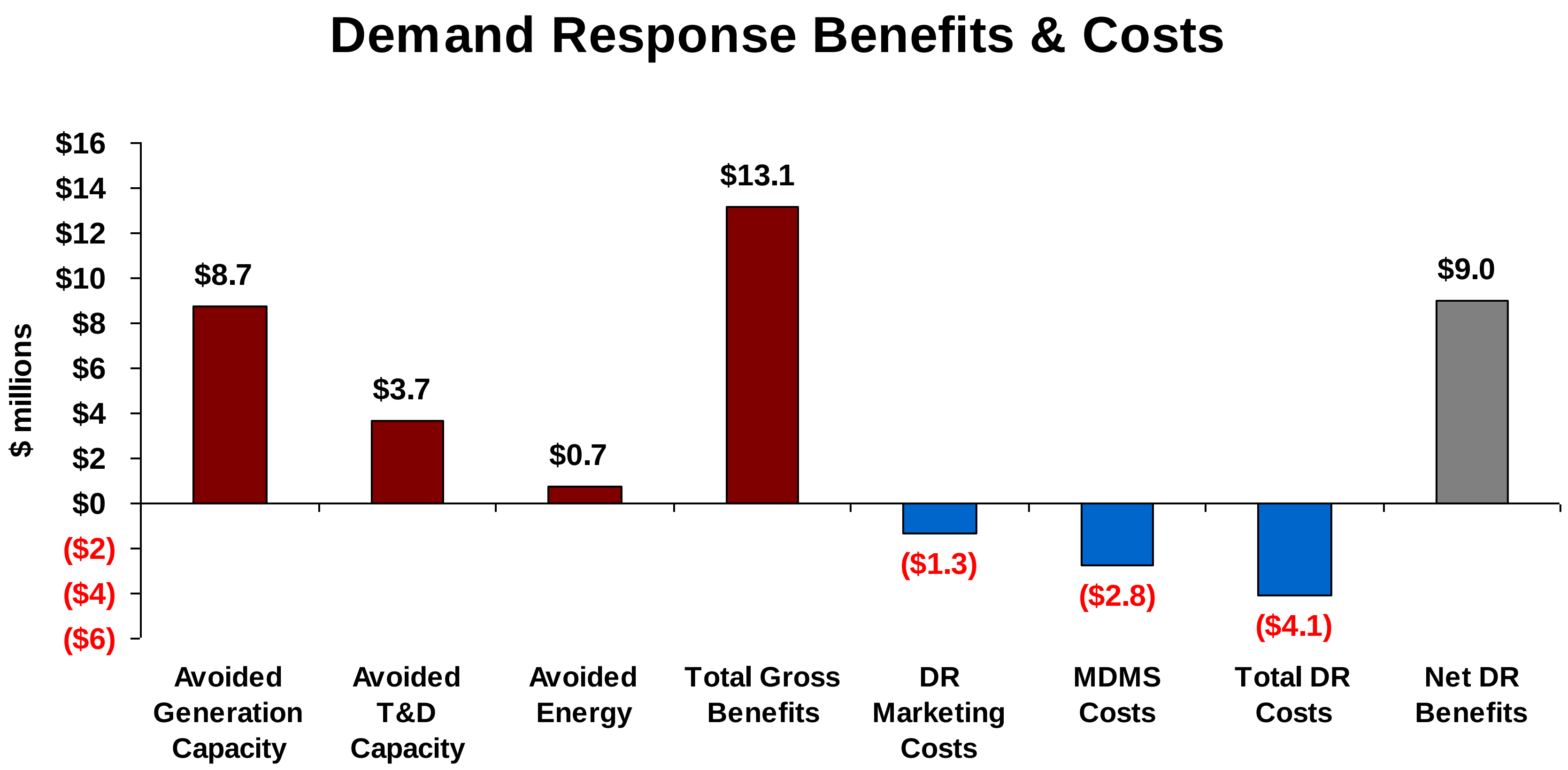


Avoided meter reading costs account for roughly 75% of total operational benefits*

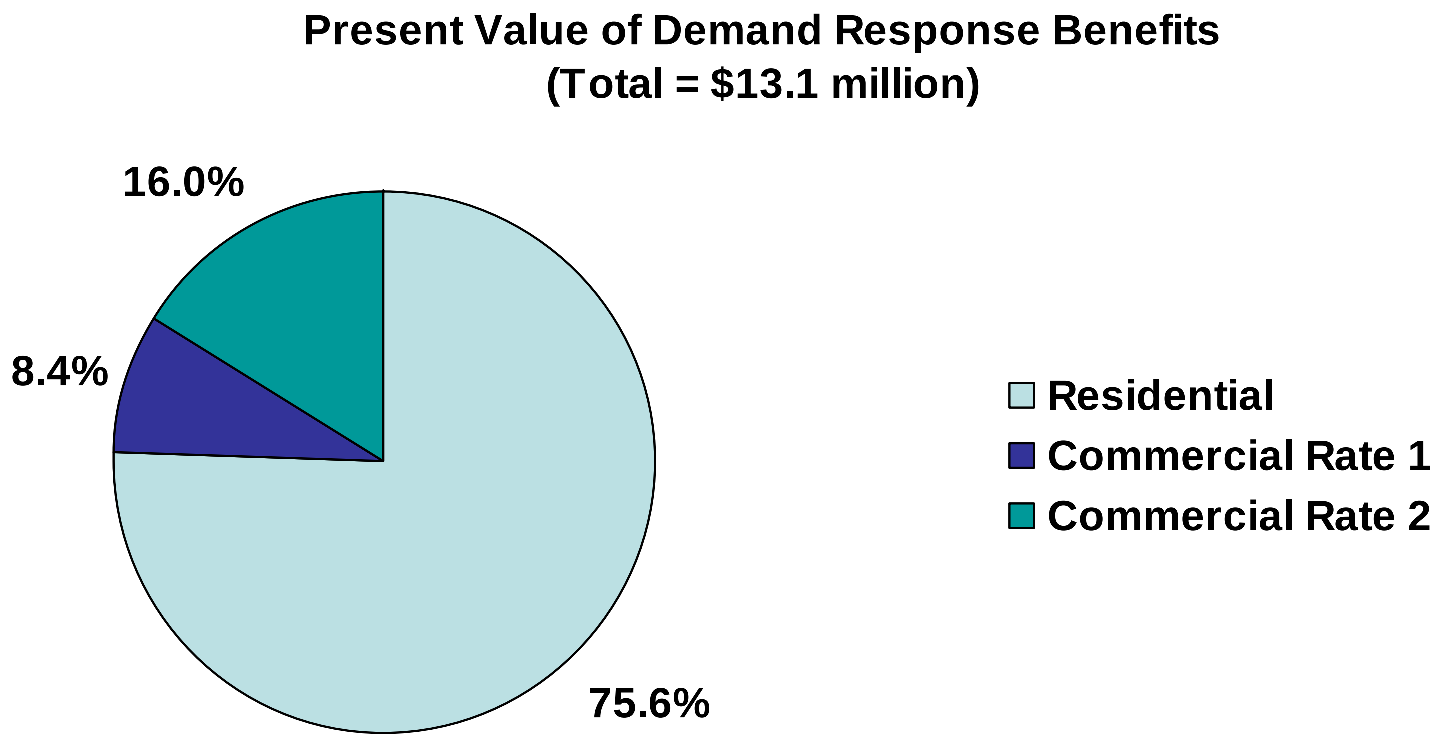


*Additional benefits would likely be identified with more detailed analysis

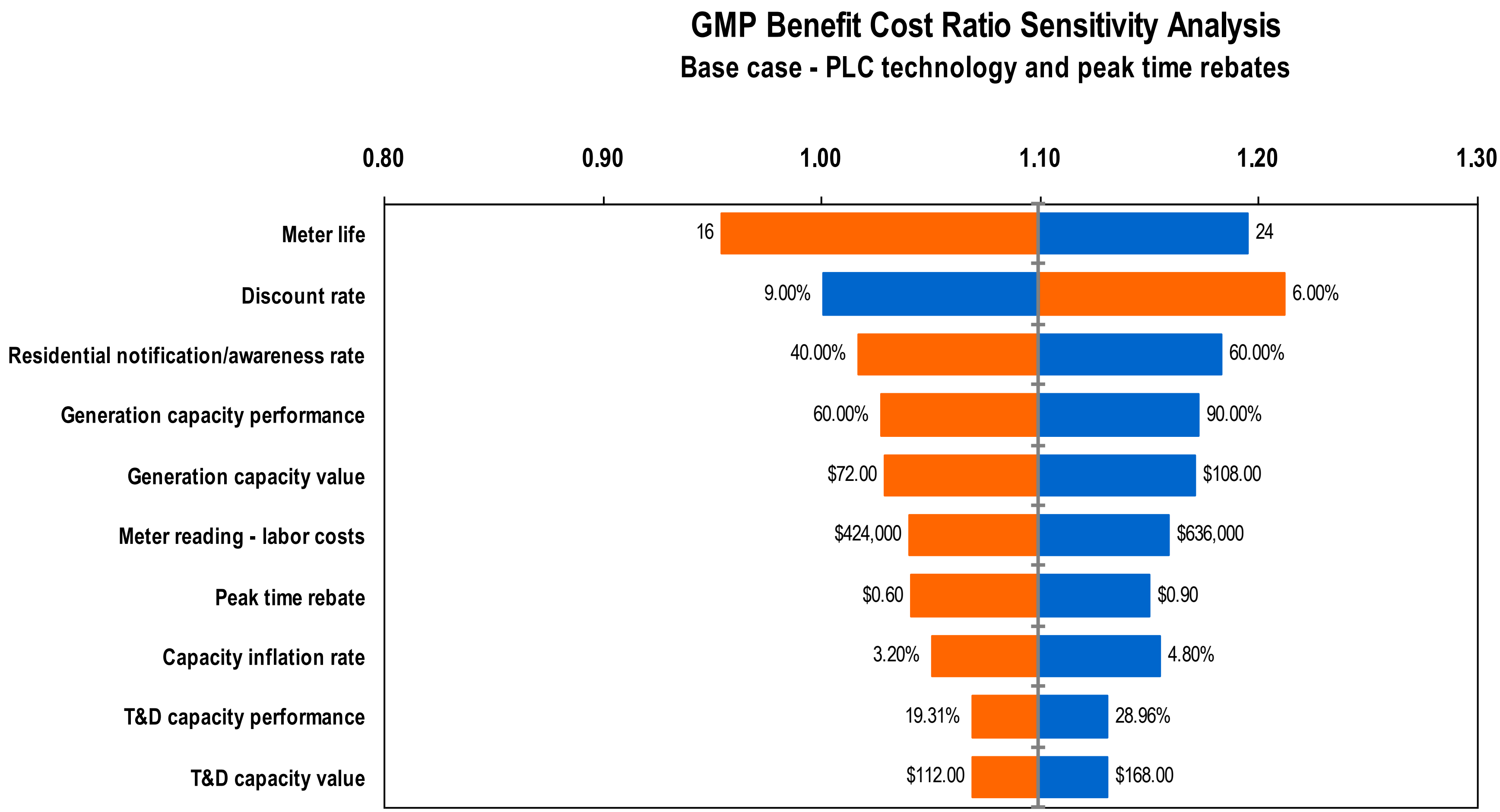
Demand response generates net benefits equal to $9 million for GMP



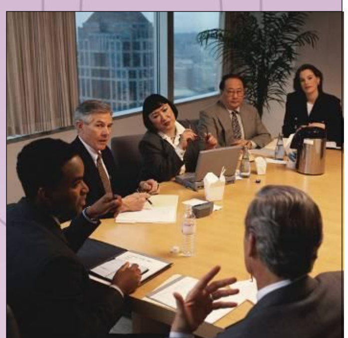
Residential customers account for 75% of DR benefits



For GMP, if expected meter life was only about 18 years, the B/C ratio would be less than 1



Preliminary Analysis Results: Vermont Electric Coop



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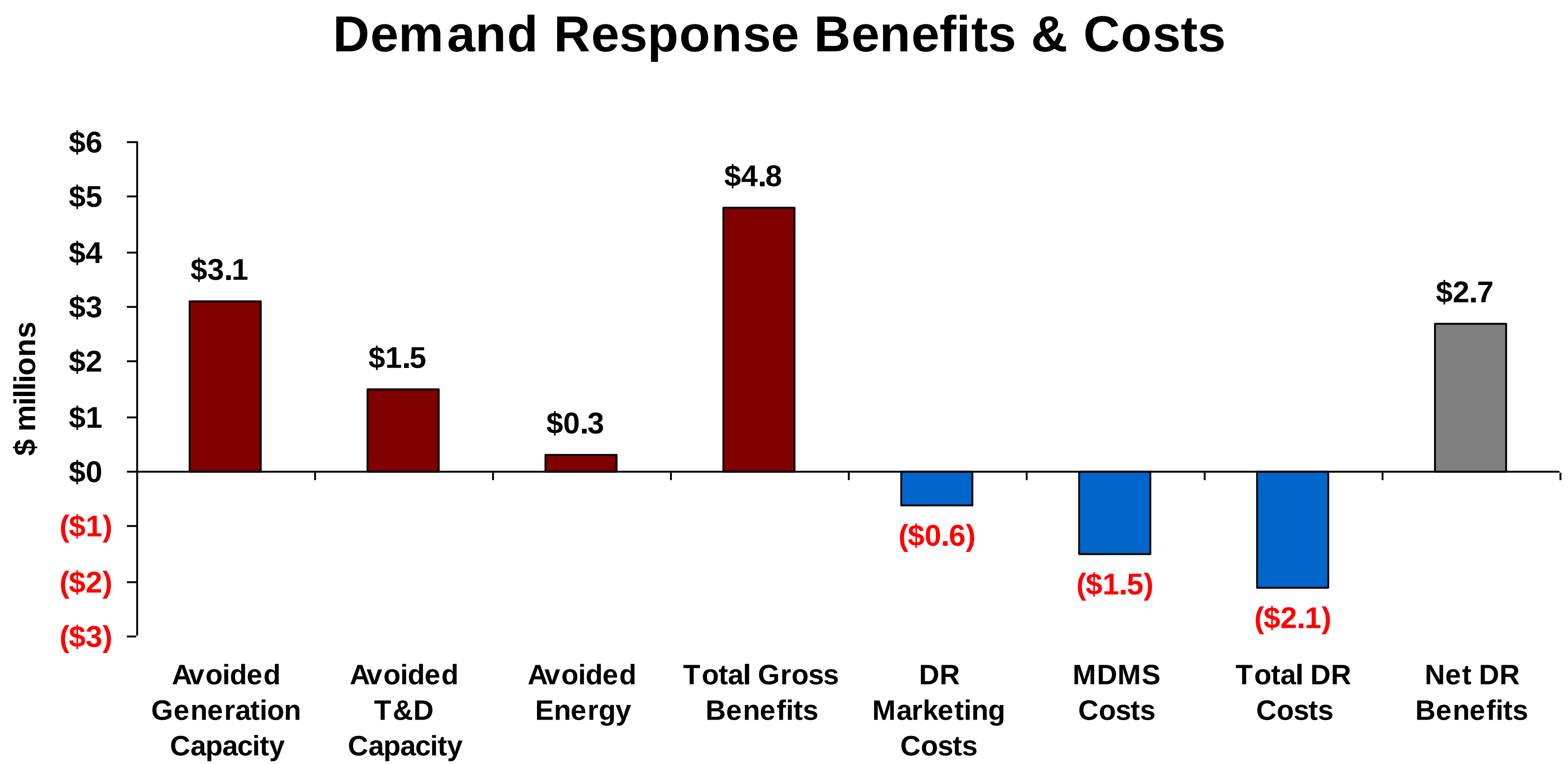
VEC Characteristics Summary

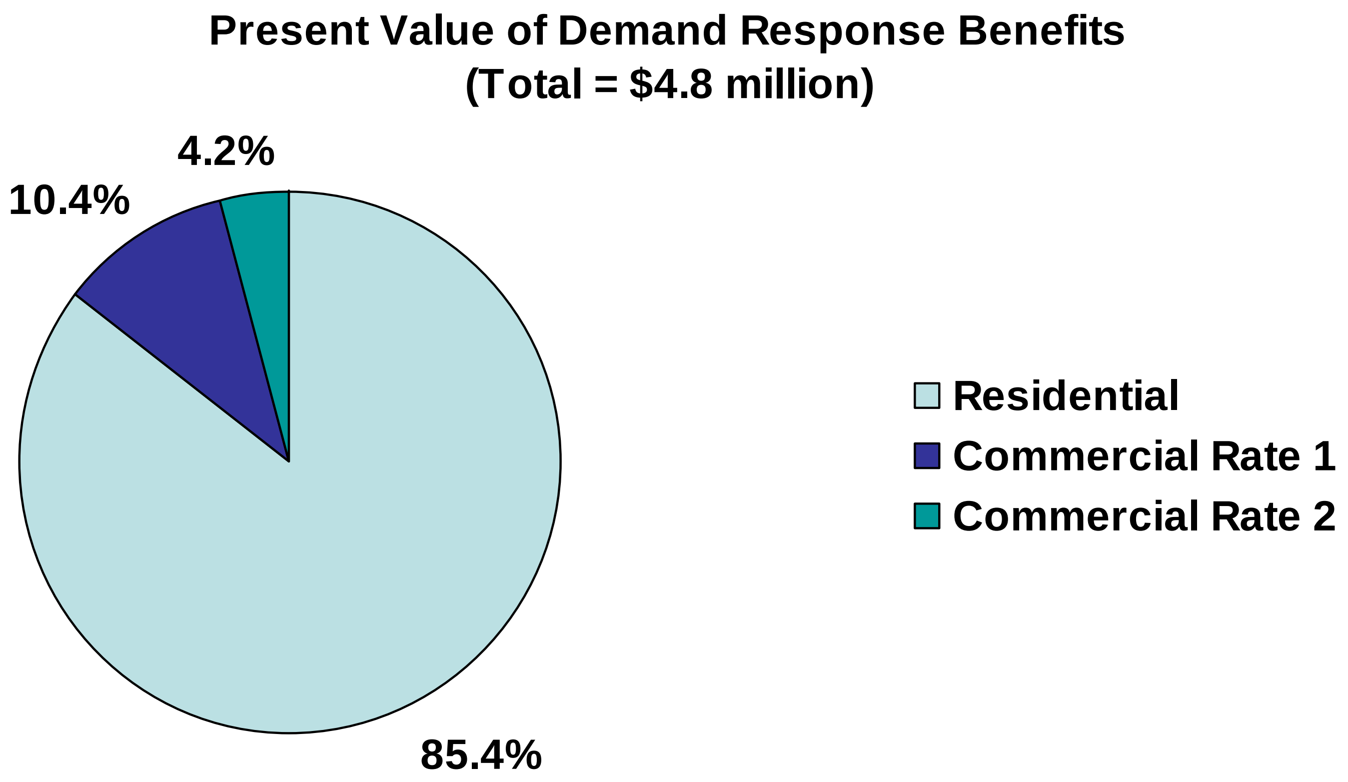
- Accounts for about 8% of VT electricity sales and about 11% of customers
- VEC is already installing AMI meters
  - Analysis only looks at the incremental cost and benefits associated with AMI
  - We assume that MDMS services would be acquired on an outsourcing basis to support time-based billing
- The analysis is based on roughly 37,000 customers
  - VEC recently sold off a small portion of it's customer base so the estimates presented here overstate slightly both the benefits and costs

The VEC analysis only examines DR benefits & costs, as VEC is already in the process of installing AMI meters*

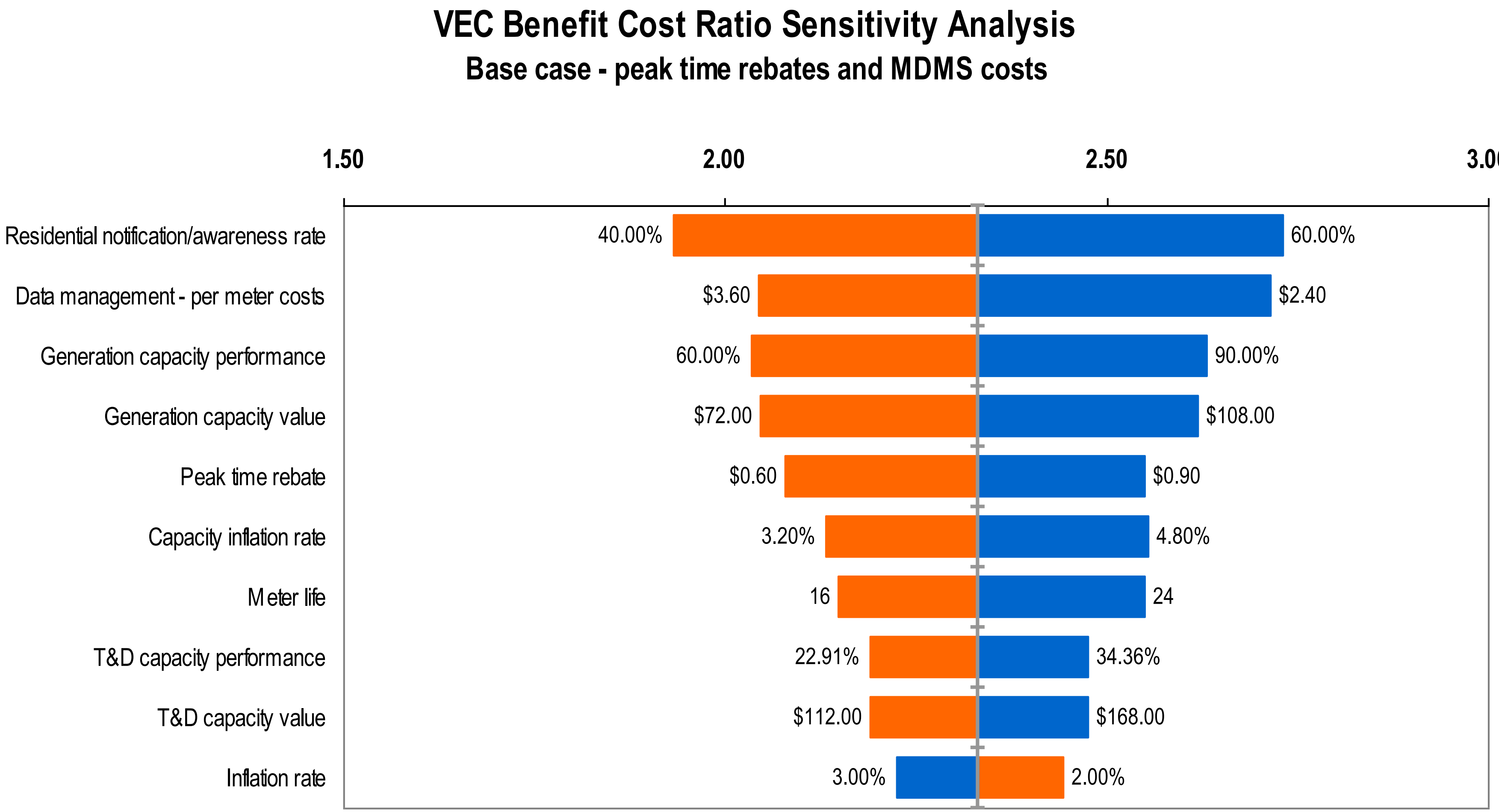


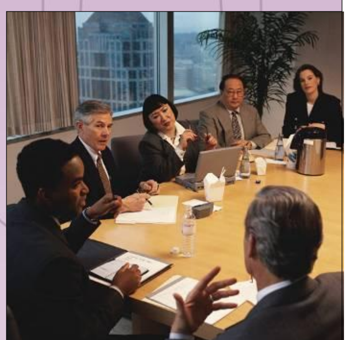
*We have assumed that VEC has not included an MDMS in it's current plans and one would be needed to support DR

Residential customers account for the vast majority of DR benefits



The VEC business case is quite robust across a wide range of input assumptions





Preliminary Analysis Results: Burlington Electric Department

FSC

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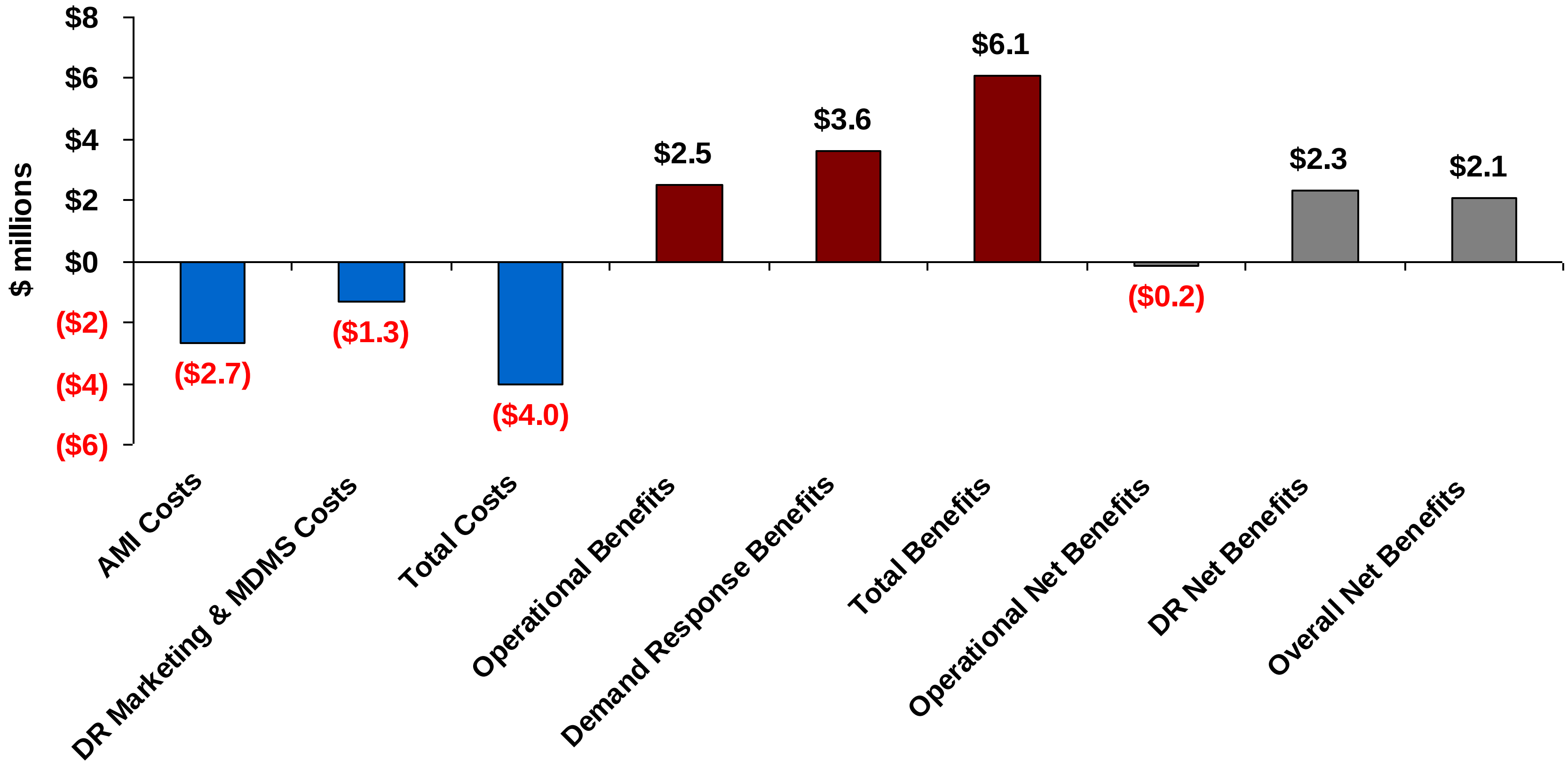
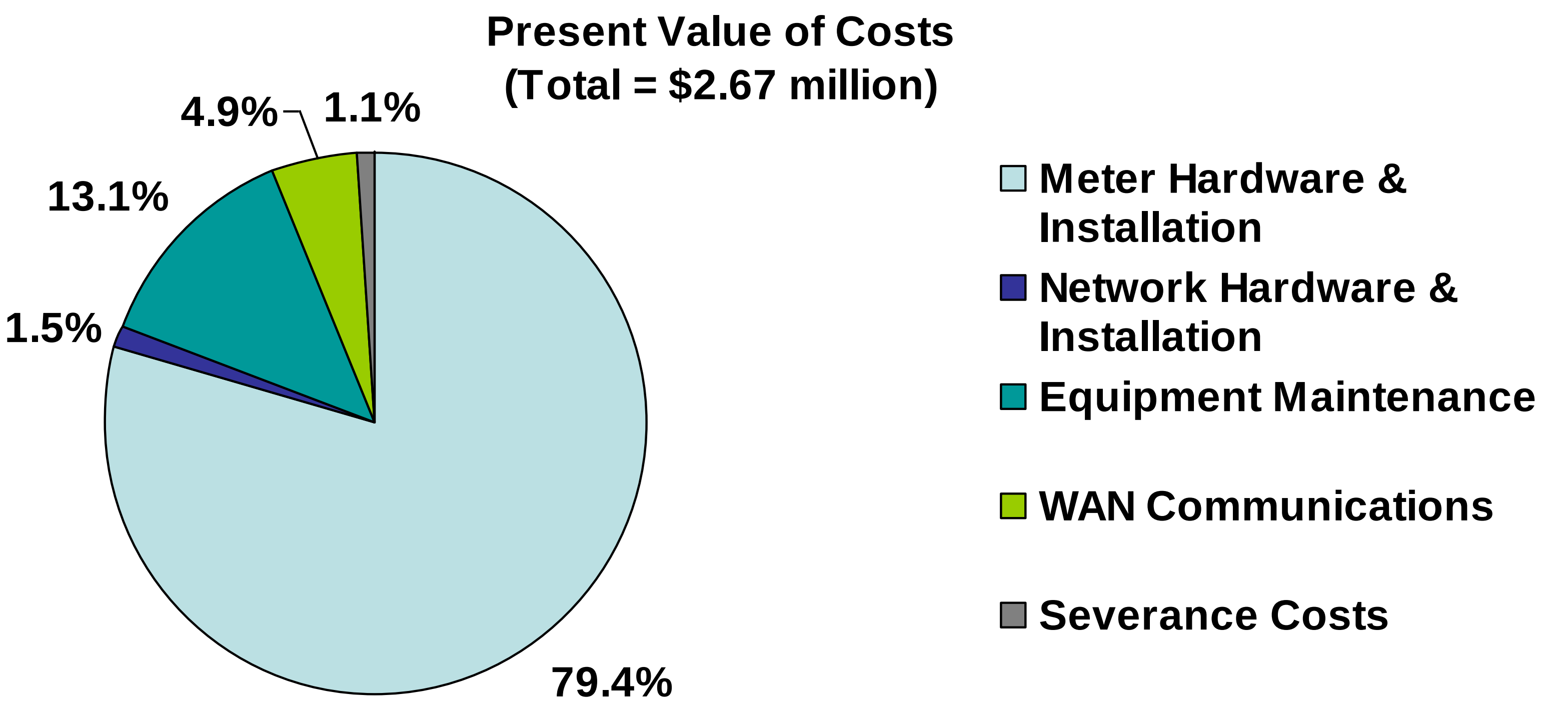
BED Characteristics Summary

- Accounts for roughly 6% of customers and electricity use
- Very compact service territory, only 16 sq. mi.
- The commercial sector has a much larger share of load
  - 72% share of peak load on high demand days
- 7 substations
- Fewer outages than other utilities
- Mesh proved to be the least cost technology

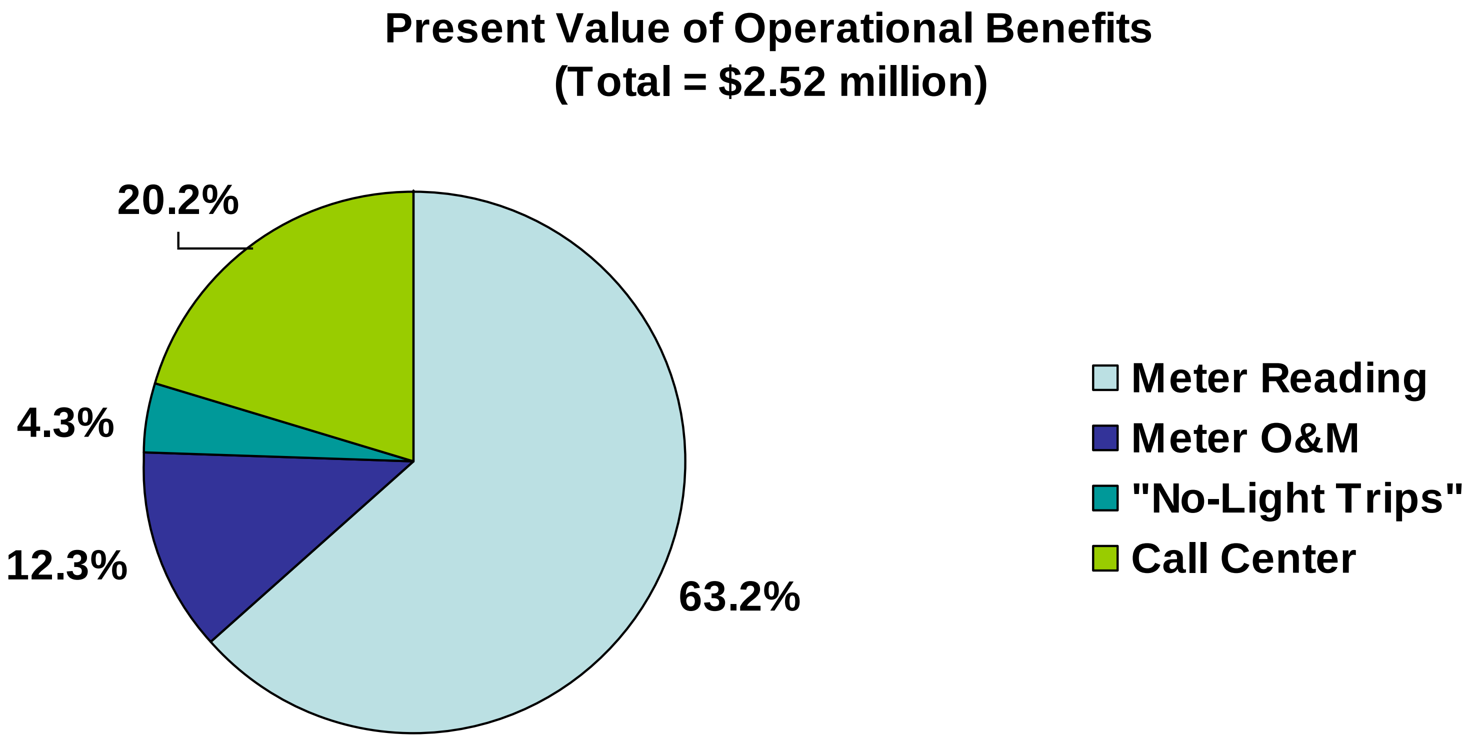
The BED business case is roughly breakeven based on operational benefits and has net benefits of $2.1 million when DR benefits and costs are included



Meter hardware and installation costs account for roughly 80% of total costs for BED

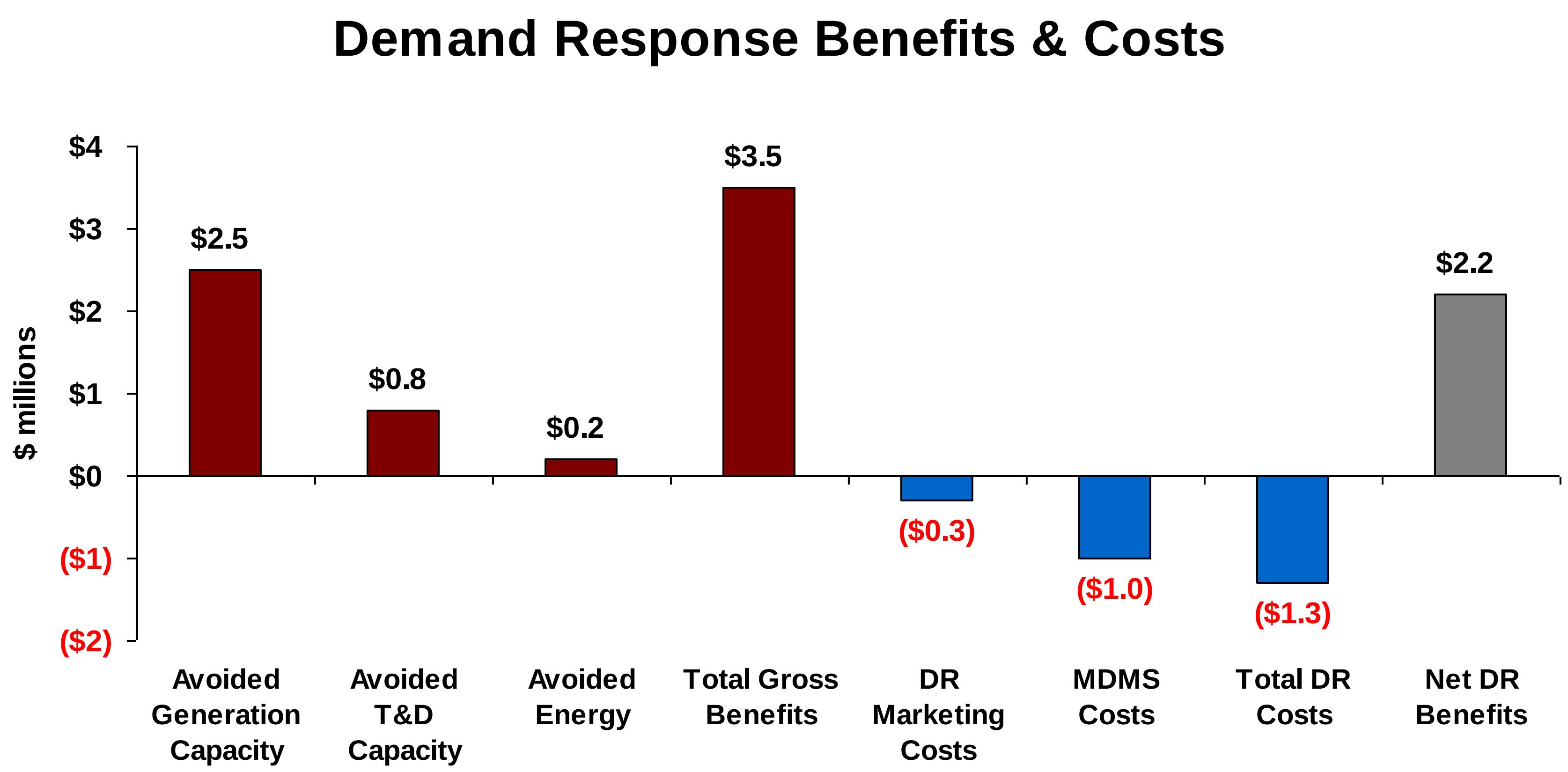


Avoided meter reading costs account for roughly 2/3 of total operational benefits for BED*

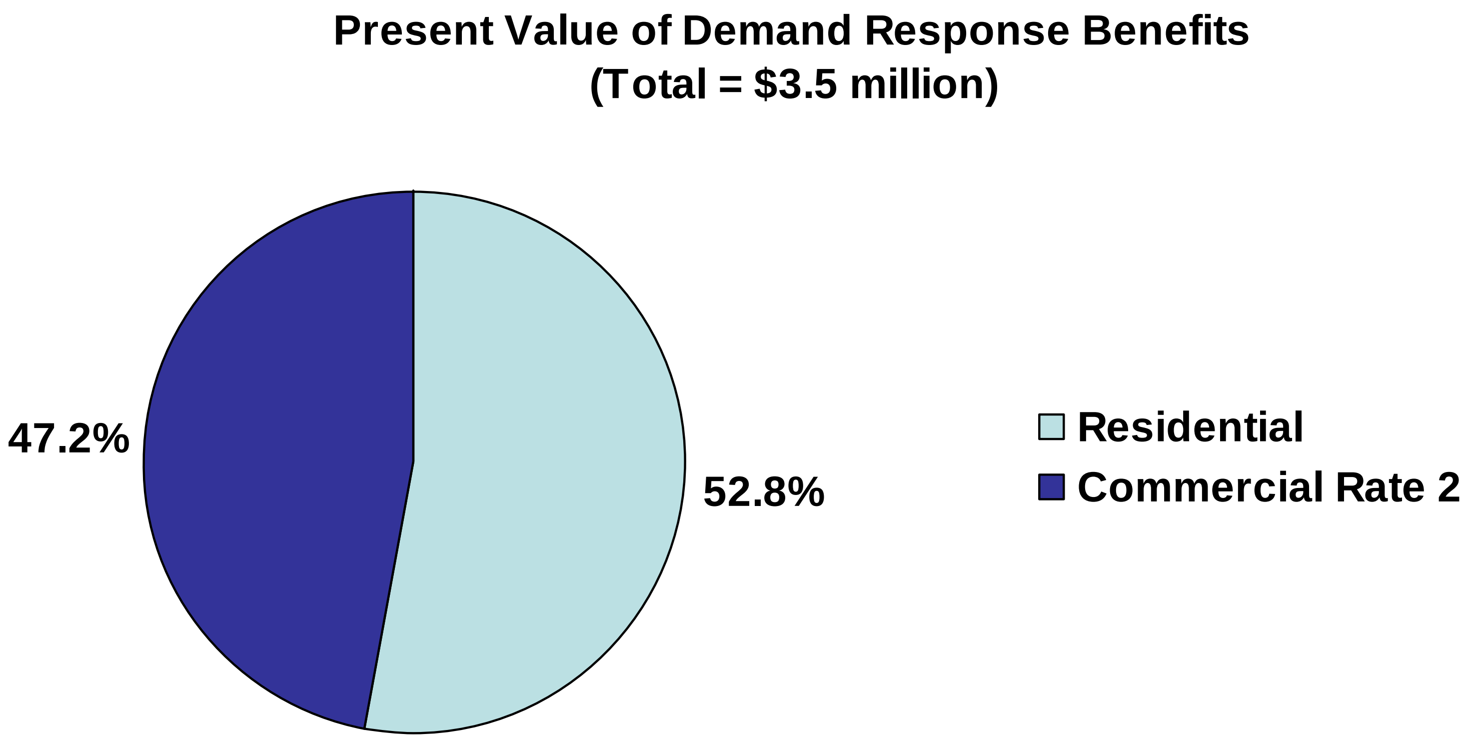


*Additional benefits would likely be identified with more detailed analysis

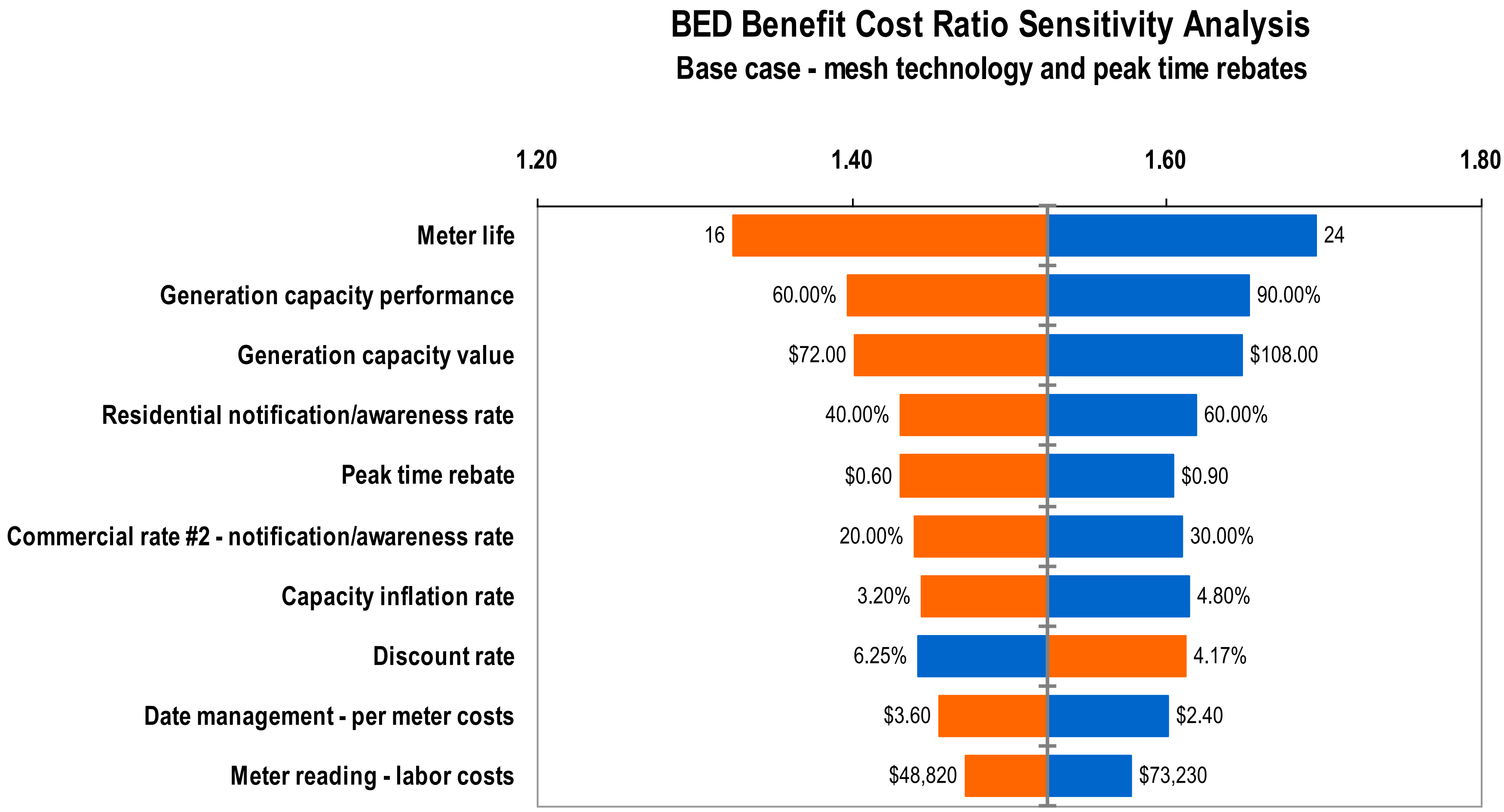
Demand response generates net benefits equal to $2.2 million for BED

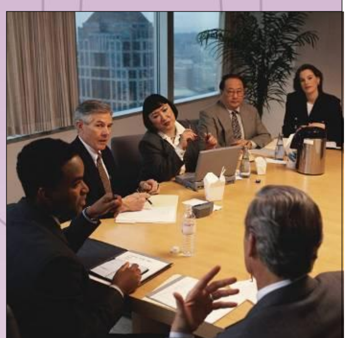


Commercial customers account for almost half of Demand Response benefits



The BED B/C ratio is quite robust across a wide range of input assumptions





Preliminary Analysis Results: Washington Electric Cooperative

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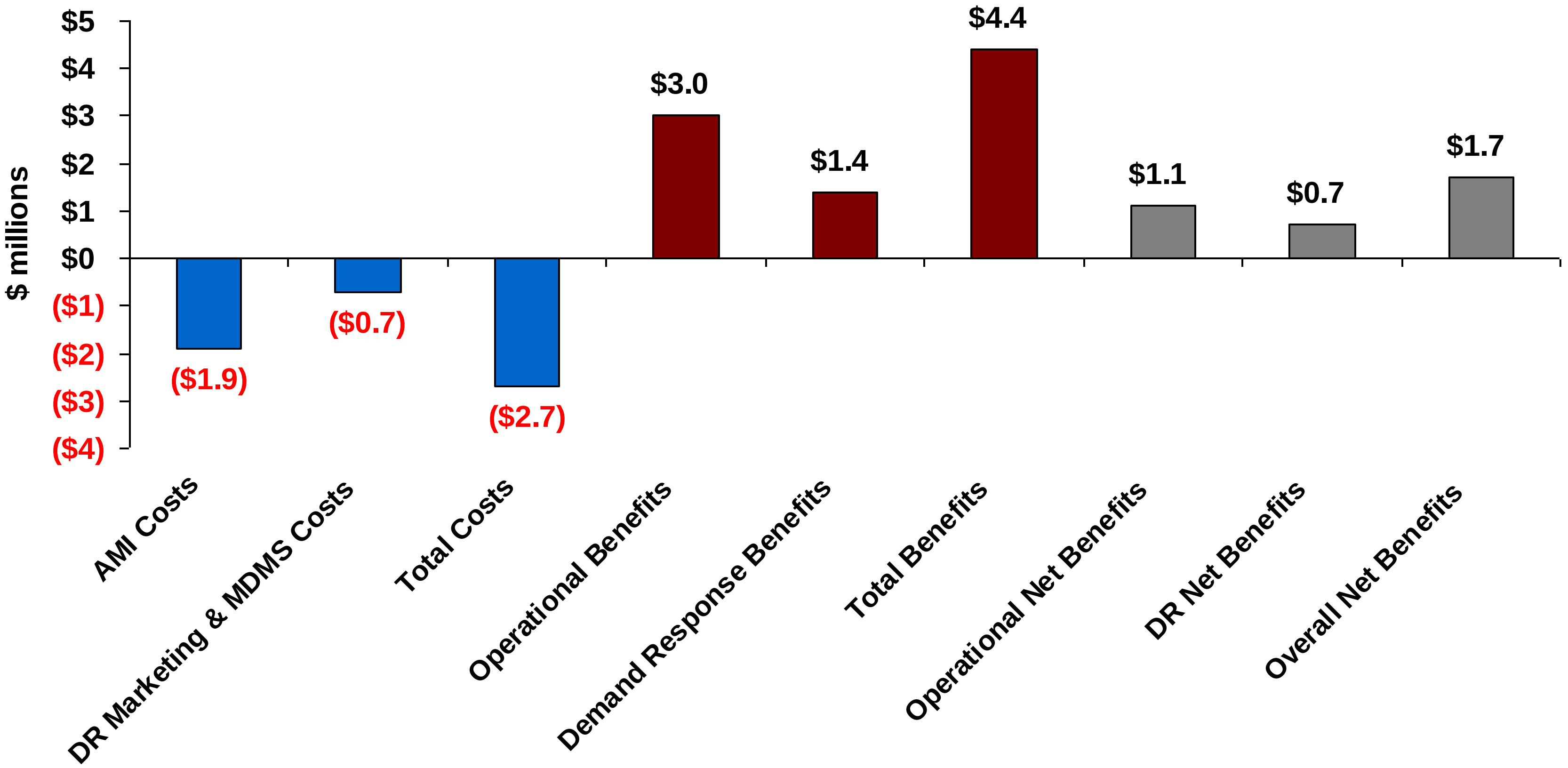
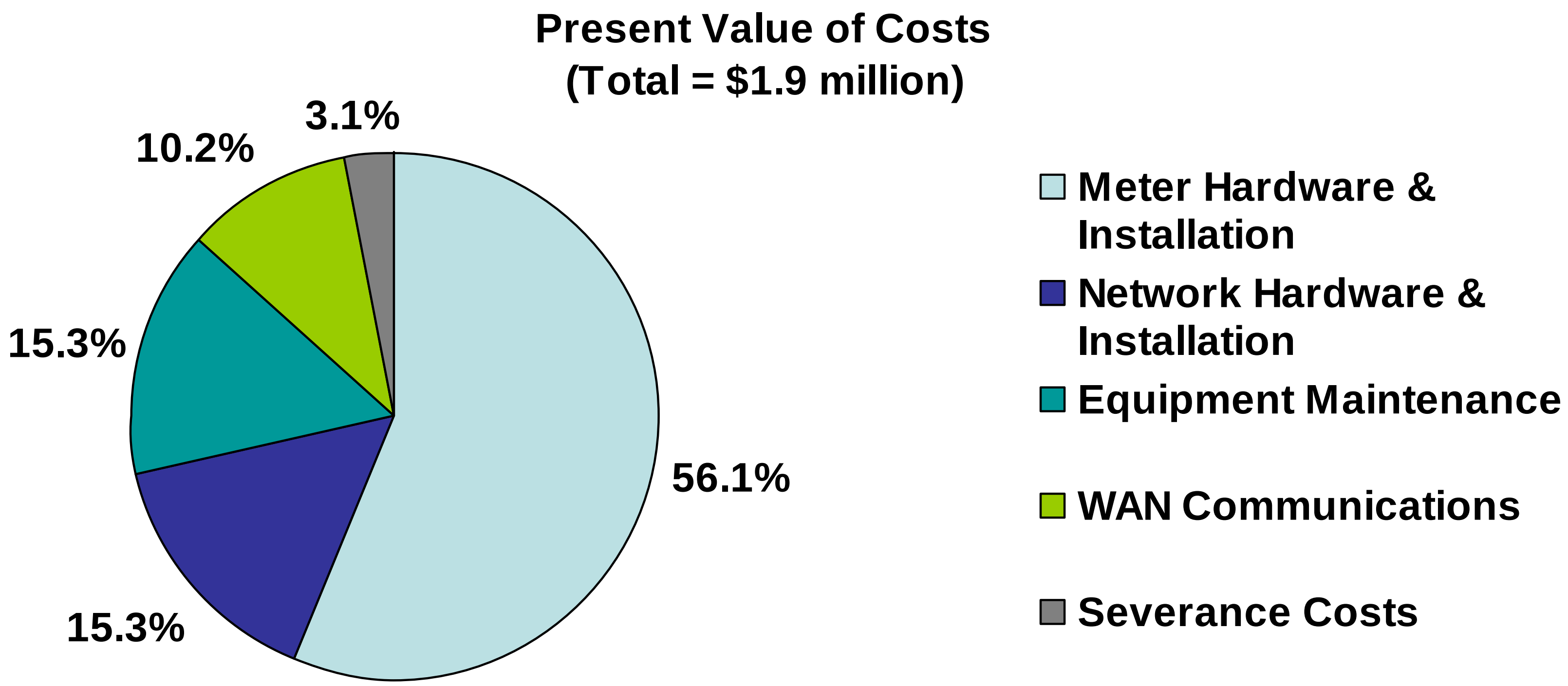
WEC Characteristics Summary

- Accounts for only about 3% of VT customers and 1% of VT electricity use
- Roughly 10,000 customers, nearly all of which are residential accounts
- 8 substations
- 1,200 sq. mi.
- Meter reading operation is contracted out
- PLC proved to be the least cost technology

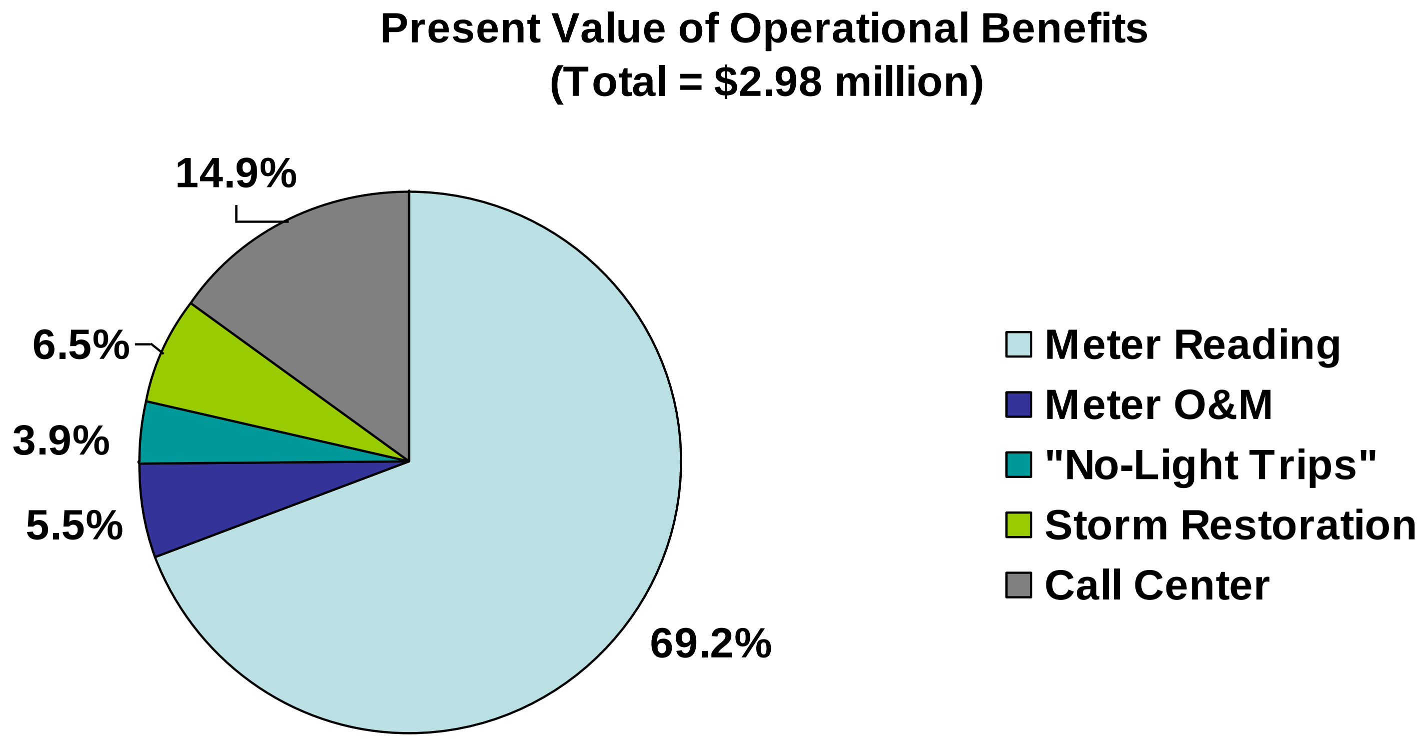
The WEC business case is strongly positive, with operational net benefits = $1.1 million and overall net benefits = $1.7 million



Meter hardware and installation costs account for roughly 55% of total costs.

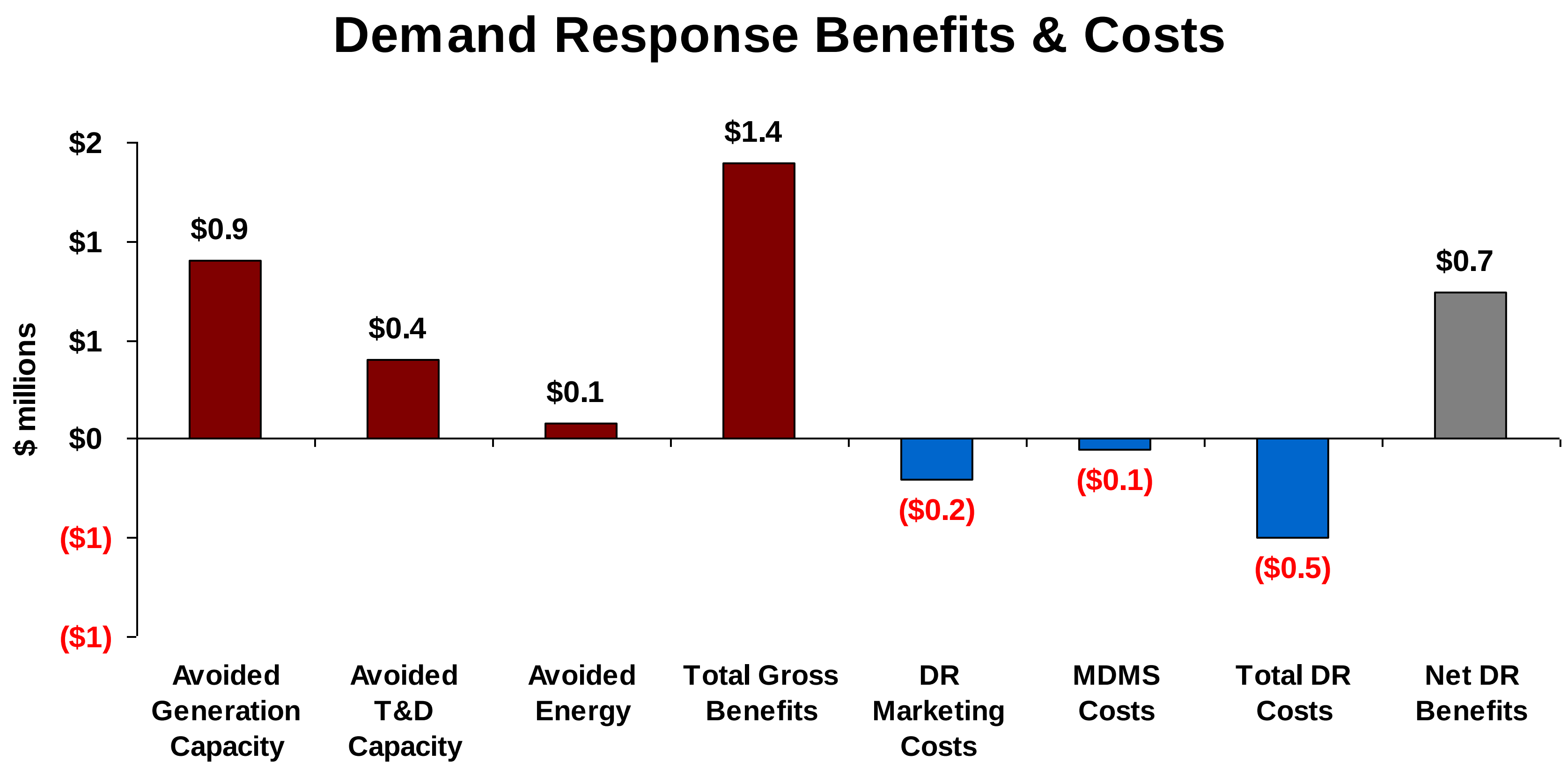


Avoided meter reading costs account for almost 70% of total operational benefits*

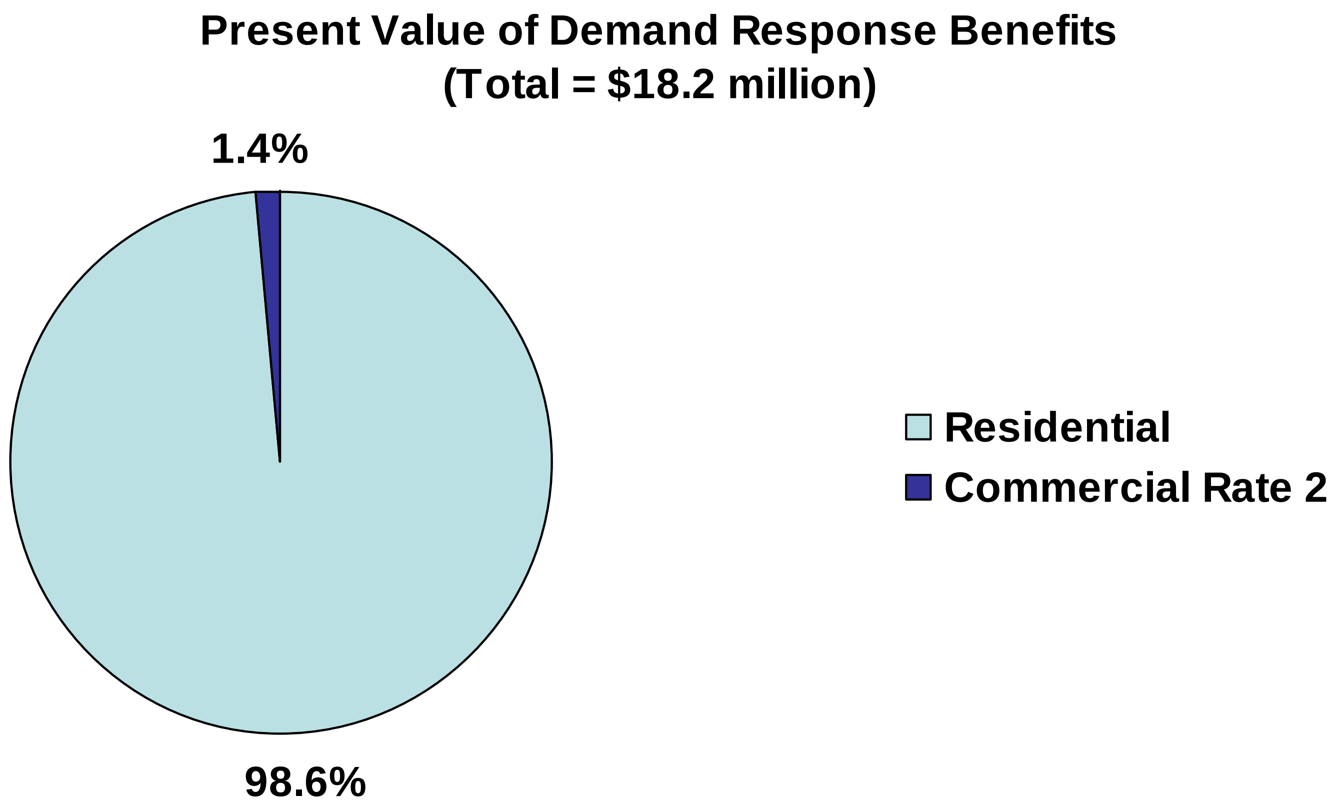


*Additional benefits would likely be identified with more detailed analysis

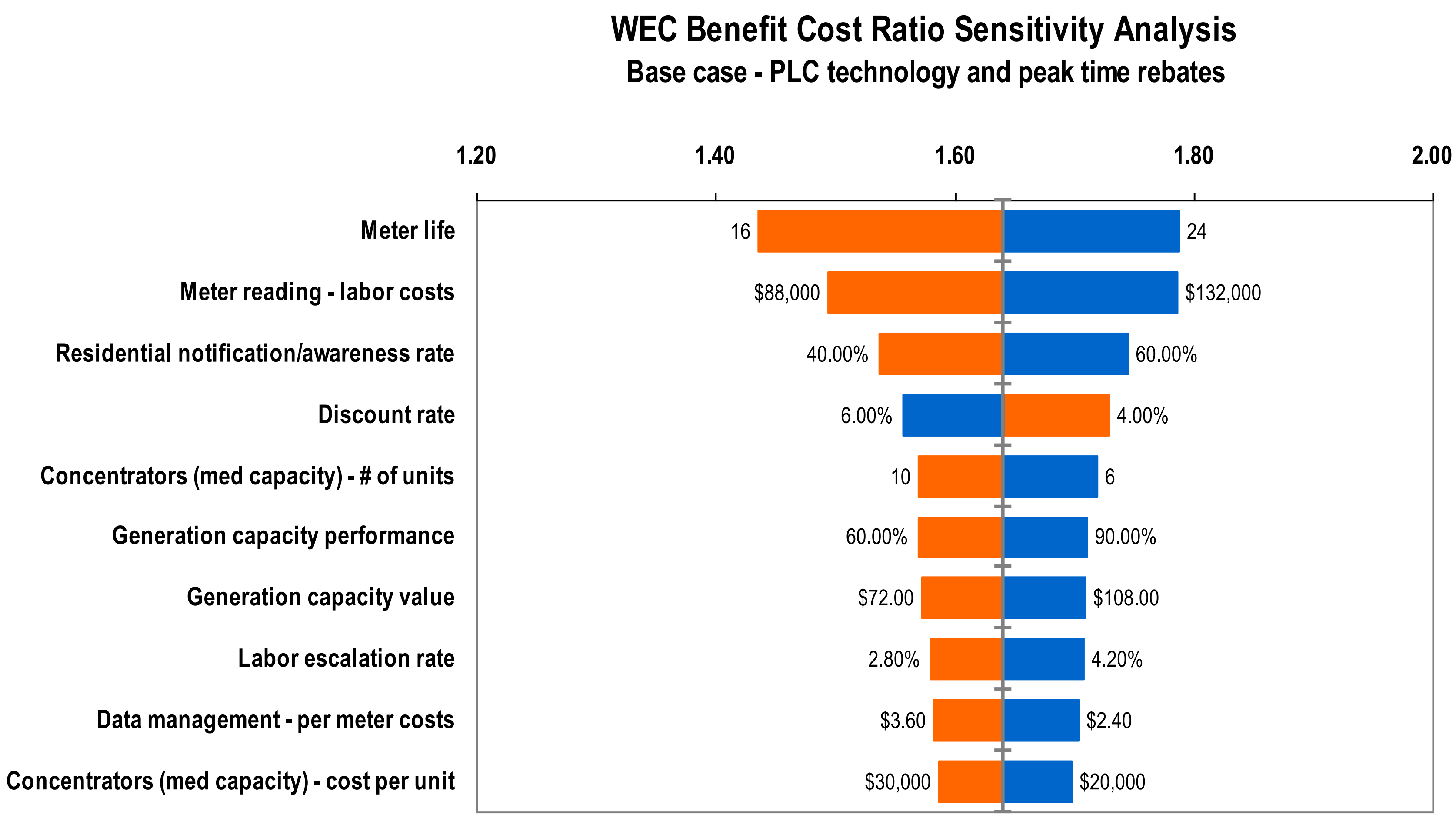
Demand response generates net benefits equal to roughly $750,000 for WEC



Residential customers account for the virtually all of the DR benefits



The WEC business case is quite robust across a wide range of input assumptions



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Appendix A
Technology Cost Analysis

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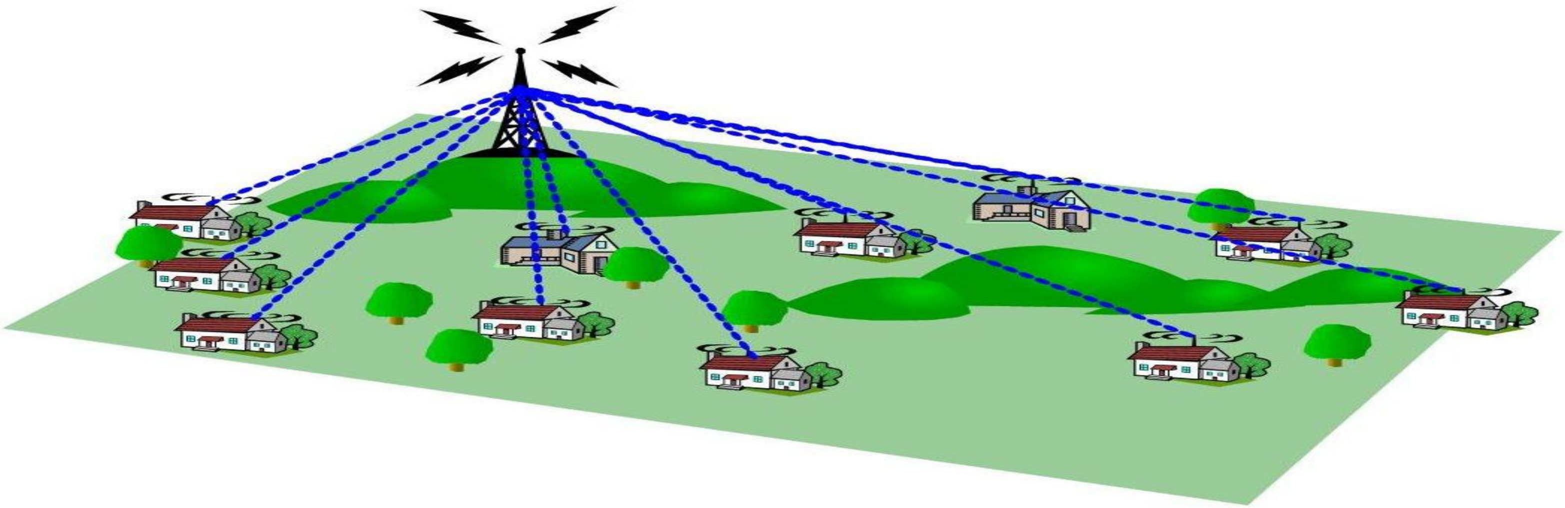
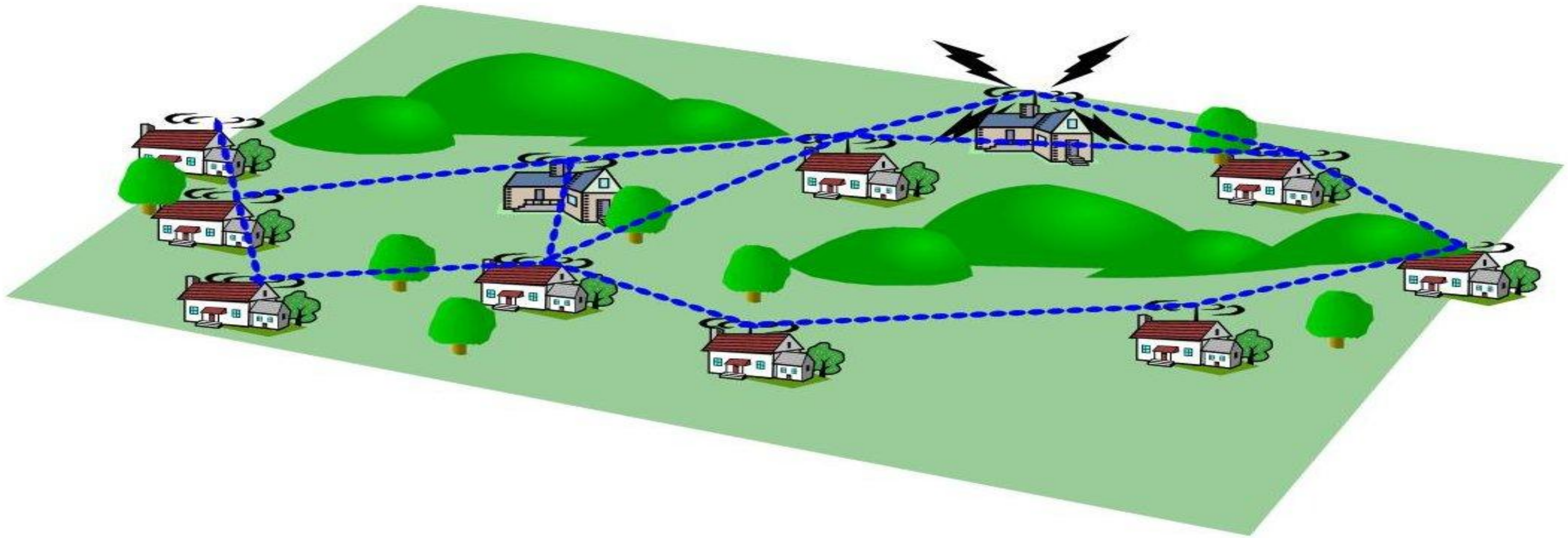
AMI star radio networks communicate over 1 to 5 miles between meters and a base station



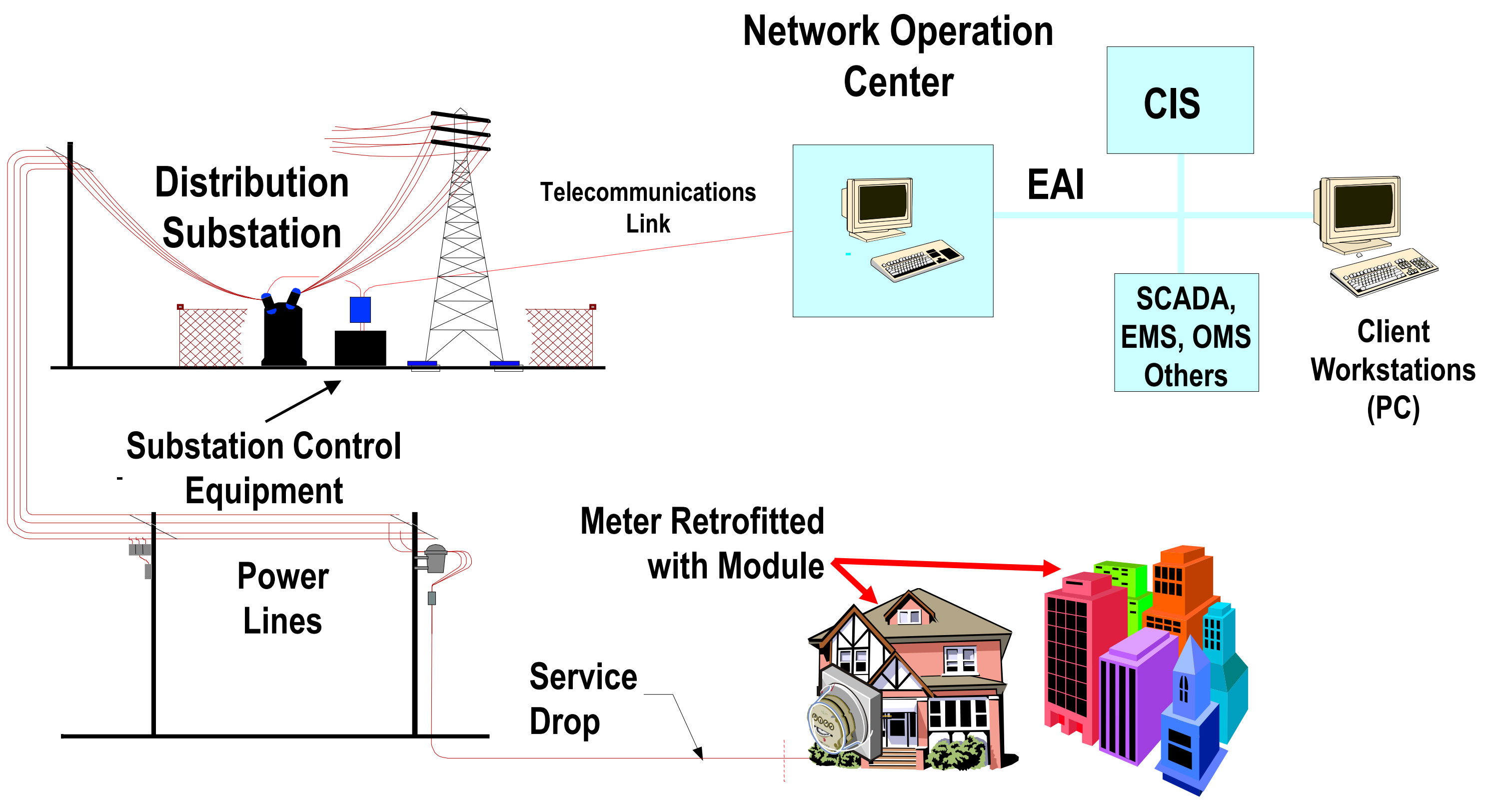
- AMI star networks support “Point to Multi Point” operation
- Base station antenna elevation must be high to achieve the range
- Require overlapping base station coverage to ensure high reliability
- Supplier examples: Hexagram, Sensus

AMI mesh radio networks leverage multiple hops to send messages 5 miles or more



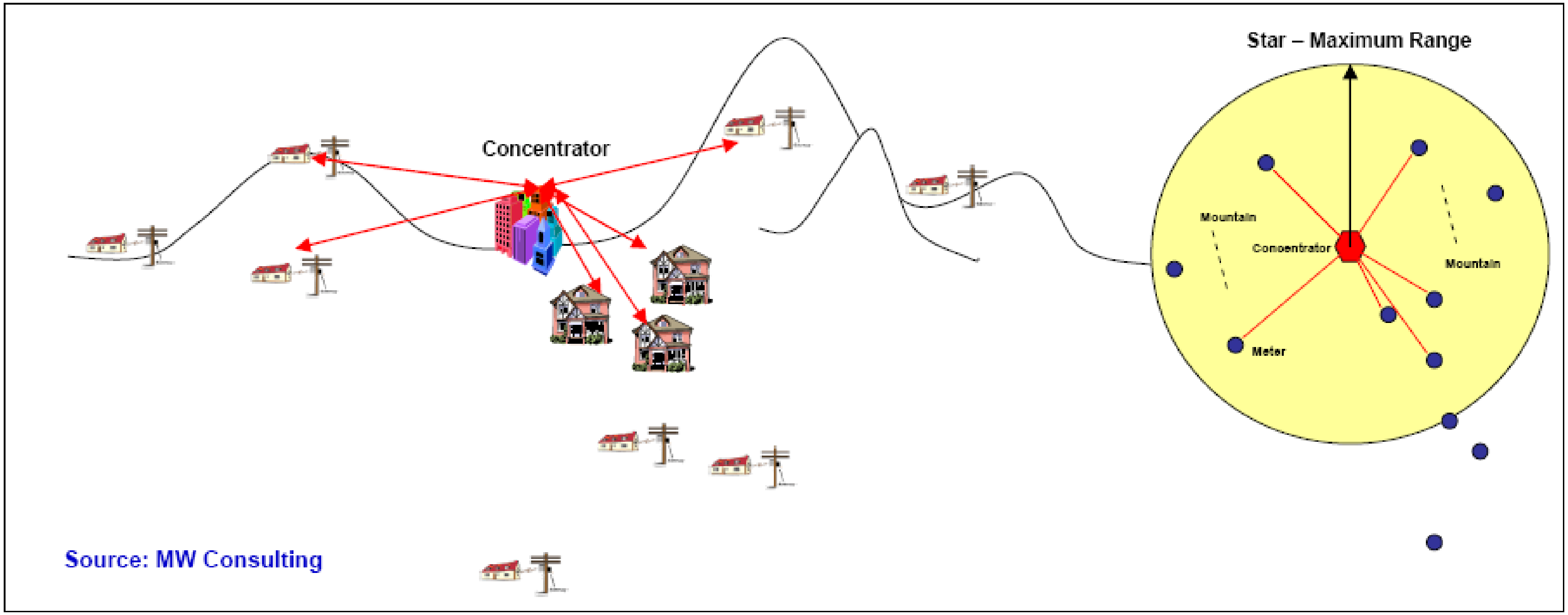
- Meters form the LAN network
- Meters forward messages to WAN access points
- Mesh systems use existing poles for access points
- Supplier examples: Cellnet+Hunt, EKA, Elster, Itron, Silver Spring Networks, Trilliant

AMI power line carrier (PLC) networks use existing power lines to send data

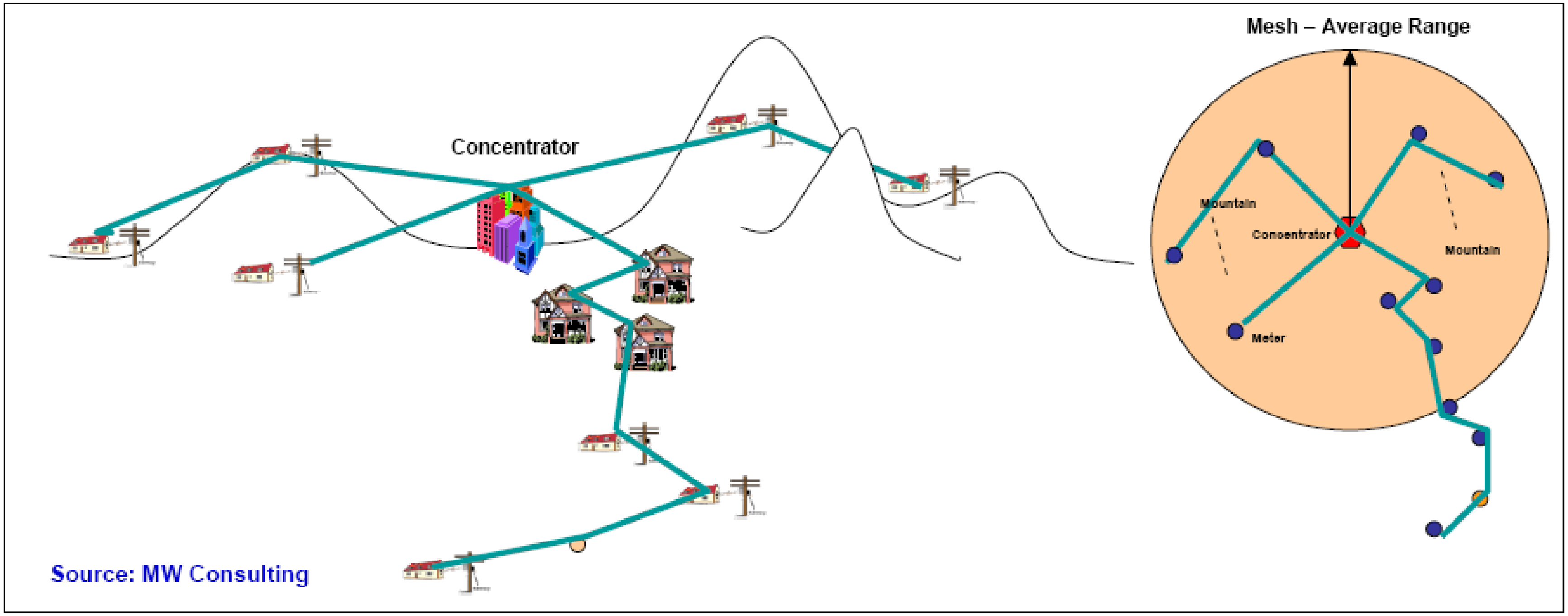


- Communicate between substations and meters
- Some systems require message repeaters
- Supplier examples:
  - Narrowband PLC - Cannon, DCSI, Cellnet+Hunt
  - Broadband PLC – Amperion, BPL Global, Corinex, Current

Hilly terrain limits the effectiveness and increases the cost of Star systems



Mesh technology can be more effective than Star systems in hilly terrain but distance between meters is an issue



Source: MW Consulting

Meter Cost Assumptions

- Meters cost about the same for similar volumes regardless of the AMI network option chosen
- Meter costs purchased in bulk for AMI deployment will be lower than the cost for AMI meters needed to accommodate customer growth in future years
  - But the cost differential between AMI and a conventional meter is about equal to the AMI meter cost during deployment
  - There is no incremental labor cost for customer growth meters
- Meter costs were held constant over time
  - Material inflation may be offset by technology improvement

Meter Cost Assumptions

Meter Type	AMI Meter Cost*	Installation Cost**
Standard Single Phase	$85	$20
Network	$125	$25
Polyphase CT	$300	$25
Polyphase CT/VT	$300	$75
All Meters	Replacement costs 150% higher outside initial roll out, 1% yearly failure rate, 5-year meter warranty	

***Not including Home Area Network or disconnect switch**
****Includes project management costs**

PLC Cost Assumptions (assuming hourly interval data is required)

Cost category	Assumption
Low capacity concentrator	Vendors claim capacity up to 4,200 meters at installed cost of $25,000. We assumed maximum capacity of 4,000 meters
High capacity concentrator	Vendors claim capacity of up to 8,400 meters at installed cost of $35,000. We assumed maximum capacity of 8,000 meter
WAN communication costs	$100/month per concentrator
O&M	Bottoms up approach based on 5% equipment failure rates, 150% replacement costs, and 5 year warranty on concentrators
Number of required concentrators	One for each substation, with cost tied to number of meters per substation and maximum capacity data above

Mesh Cost Assumptions

Cost category	Assumptions
Concentrator	Vendors claim capacity up to 4,500 meters at installed cost of $1,000. We assumed maximum capacity of 3,000 meters
Repeater	Used to connect meters that are too far apart to communicate with each other. Cost is $300 each.
WAN comm. costs	$100/month per concentrator
O&M	Bottoms up approach based on 5% equipment failure rates, 150% replacement costs and 5 year warranty
Number of required concentrators	One per 20 square miles or 1 per 3,000 customers, whichever gives the largest number of concentrators
Number of required repeaters	1 per 10 customers outside town centers

Short Range Star Cost Assumptions

Cost category	Assumption
Concentrator	Vendor claims capacity of 10,000 or more for an installed cost of $2,000 per concentrator. Three square mile range. Need overlapping range for effective coverage, reducing effective range to assumed 1.5 square miles.
WAN communication costs	$100/month per concentrator
O&M	Bottoms up approach based on 5% equipment failure rates, 150% replacement costs and 5 year warranty
Number of required concentrators	One concentrator for every 1.5 square miles

Another key input for the AMI cost analysis is the number of meters

- The number of meters and number of customers differ
  - Both figures came from data requests
- Deployment costs are tied to number of meters by type
- The number of meters for customer growth beyond the deployment period are tied to population growth
  - So far, we have assumed annual growth rates of 1% for residential customers and 0.5% for business customers
- Implicitly, we assume that the number of meters by type stays constant over the forecast horizon

Number of meters by type and utility

Utility	Single Phase	Network	Polyphase CT	Polyphase CT/VT	Total
CVPS	171,691	3,614	3,484	1,374	180,162
GMP	87,707	1,793	4,703	0	94,203
VEC	n/a	n/a	n/a	n/a	n/a
BED	18,947	419	481	14	19,861
WEC	10,265	0	0	0	10,266

Deployment Schedule

- We assume that meter installation would start on May 1, 2009 for all utilities
  - We only assume that DR benefits count for meters that are installed prior to summer of each year and a May 1 start date avoids calculating benefits for only a few meters in the first year
- For CVPS and GMP, we assume a 24-month installment period
- For all other utilities, we assume a 12-month installment period
- The network costs are rolled in according to the following schedule
  - Network installed in proportion to meter installations, lagged 2 months

Other inputs

- Weighted average cost of capital (WACC) from each company used as discount rate
- Tax rate for CVPS and GMP at 39.5%
- Severance costs assumed to be 1 week for each year of employment
  - Calculated based on average years of employment data provided by each utility

Appendix B: Operational Savings Assumptions

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Avoided meter reading costs

- Obtained meter reading cost data from each utility
  - Grow labor and overhead costs at a labor inflation rate of 3.5%
  - Grow vehicle and equipment costs at a general inflation rate of 2.02%
  - Grow both labor and vehicle/equipment costs at customer population growth rate
    - Assumes that costs grow smoothly with population when in reality additions to meter reading staff and vehicles and equipment would be more like a step function with additions made as population growth exceeds certain thresholds
- Avoided costs are reduced by one-time severance costs
  - Severance costs are incurred each year of the deployment period in proportion to the percent of meters that have been replaced

Field operations cost savings

- Avoided “no light” calls
  - Data request information on the number of “no light” trips for which the outage was on the customer side of the meter and the average cost per trip

Storm restoration cost reductions

- Ability to ping meters to determine if service has been restored when crews are still in the field has been demonstrated to reduce restoration costs
- Assumed a 10% reduction in storm budgets
- Not all utilities provided storm budget data
- Made estimates for those who didn't based on those who did, except that we assumed BED was different enough that we couldn't extrapolate
  - No storm restoration benefits for BED

Call center cost reductions

- Elimination of estimated bills reduces bill inquiry call volume
- Assumed a 10% reduction in non-storm related call value
- Used data on call minutes and call types from utilities to estimate call minutes for non-storm related calls

Appendix C:
Demand Response Benefit Assumptions

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Average annual electricity use (kWh)

Utility	Residential	Commercial Rate 1 (Medium customers >10 kW or >20,000 kWh))	Commercial Rate 2 (Other rate targeted at medium or large (<200 kW) customers)
CVPS	6,327	44,488	286,390
GMP	6,757	33,045	160,221
VEC	6,104	59,995	147,945
BED	5,139	n/a	212,308
WEC	5,690	n/a	193,124

Meter Data Management System Costs

- An MDMS
  - Obtains data from the AMI system
  - Implements VEE rules to convert raw data to billing quality data
  - Produces billing determinants, including those required for time-based billing
  - Interfaces with the billing and CIS systems
- There are three options for developing MDMS capabilities in conjunction with AMI deployment and time-based pricing
  - Purchase a system
  - Out-source the function
  - Develop in-house systems to provide MDMS functionality required to support AMI

MDMS Purchase Option Cost Assumptions

- Given the set-up and licensing fees, there is a minimum number of customers for which this option makes sense
  - This option is only feasible for CVPS and GMP
- We have assumed the following “ball park” costs for an MDMS purchase option for these 2 utilities
  - One-time license fees ~ $300,000
  - One-time set-up costs ~ $300k for CVPS, $200k for GMP
  - Annual license upgrades ~ 20% of license fees
  - Hardware purchase (e.g., servers, etc.) ~ $50,000
  - $1/meter/month in additional costs

MDMS Outsourcing Option

- Nexus Energy Software recently began offering MDMS services on an outsourcing basis
- Their target market extends to utilities with as few as 20,000 customers
  - VEC and BED exceed this threshold
  - Whether a number of smaller utilities could work together to obtain these services on an outsourcing basis would depend critically on whether they have unique or common CIS and other systems with which the MDMS must interface
  - Assessing whether or not this is feasible is beyond the scope of this project
- Set-up costs for this service will depend on the nature of the CIS and billing systems at each utility and the number of required interfaces with existing systems
  - We have assumed a set up cost of $100,000 for these 2 utilities
- A reasonable assumption for processing costs is $2 to $4 per customer per year
  - We have assumed $3/customer/year